THE UNIVERSITY OF ALBERTA

THE PRICING OF CRUDE PETROLEUM IN CANADA

by

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled "The Pricing of Crude Petroleum in Canada" submitted by Andre Bourassa in partial fulfilment of the requirements for the degree of Master of Arts.

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ABSTRACT

An important question associated with the pricing of crude oil is whether the interests of the provincial governments, who own the majority of the known reserves of crude, are consistent with those of the producers of crude. There are a number of possible divergencies between the interests of producers and provincial governments. The most important source is the fact that the largest producers are integrated and also have a low degree of self-sufficiency in crude. Their interests as buyers of crude outweigh their interests as producers. The largest integrated oil company in Canada, Imperial Oil, is generally accepted as the price leader in the industry.

An attempt was made to determine whether the price of crude was more consistent with the interests of the integrated oil companies or the provinces. This approach was not wholly successful because a study of the demand curve facing Canadian crude failed to explain fully its position in the North American markets. Canadian crude enjoys a "special status" relative to other imports from other countries. The presence of non-price factors makes it very hard to

determine what should be the price of Canadian crude to be on the price elastic portion of its demand function. From the drop in the price of U.S. import tickets over the last two years and the price trend of both U.S. and Canadian crude over the last decade, it seems that Canadian crude is underpriced although the information for a precise measurement of the gap is at present not available.

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Chapter 1

INTRODUCTION

In the winter of 1971-72, when the Alberta government decided to raise its revenues from the oil industry, the reaction of the companies involved was immediate. Their spokesmen came to the government's hearing, arguing that any measure affecting their profit margin was going to compel them to increase the price of crude oil. This increase, it was argued, would endanger the marketing prospects of Canadian crude. The government was maintaining that it was possible, without any harm done to the competitive position of Canadian Oil in North American markets, to increase its revenues from taxes and royalties. These opposing views once more reflected the possibility of conflict that exists between the goals pursued, both by the government and private companies, although they both are probably interested in obtaining the highest returns from the exploitation of that resource.

The purpose of this study will be, first to try to identify the goals that are most likely to motivate the activity of the government and the companies, whether they have a multinational or more local character; and then see how the system in which they are operating

allows them to attain these goals more fully. This will be the undertaking of Chapter 3. Chapter 4 will try to tackle the question of the competitiveness of Canadian crude in North American markets by determining the demand curve facing Canadian crude. Before putting the reader in the midst of the discussion, Chapter 2 is intended to give some sort of historical perspective to the development of the Canadian crude oil industry.

Chapter 2

HISTORICAL SETTING OF THE CANADIAN CRUDE OIL INDUSTRY

DEVELOPMENT OF CANADIAN CRUDE OIL INDUSTRY

Although there is quite a long history of crude oil exploration and production in Canada, it was not until the Alberta Leduc oil discovery in 1947 that the real foundations of today's Canadian crude oil industry were laid. Crude oil production can first be traced back to 1862 in Ontario, and there is even evidence of oil discoveries as early as 1858. Crude oil production was then concentrated in the Oil Springs and Petrolia districts of Southwestern Ontario; it reached a peak of 829,000 barrels in 1894. It was to decline later to a level of less than 200,000 barrels.

This crude oil production led to the establishment of refineries in that area. In 1867 there were 25 small refineries, with an average daily capacity of 70 barrels each.

In the early 1900's, the Stony Creek field near Moncton, New Brunswick, was brought into production; but it was never to exceed the 31,000 barrels per year

mark. In 1920, the Norman Wells oilfield was discovered in the Northwest Territories; its production peaked at 1,224,000 barrels in 1944 when oil was carried through pipeline to Fairbanks, Alaska, as part of the war effort of the Allied forces under the Canol Project.

Although oil was known to exist in Alberta as early as 1788 when Peter Pond, a northern explorer, noticed oil seepages from the tar sands in the Fort McMurray area,[1] it was not until the end of the nineteenth century that some form of systematic search for oil was undertaken. Gas fields were first discovered in Medicine Hat in 1890 and then in Turner Valley in 1914, which also yielded a small amount of very light liquids.

The first significant crude oil discovery in Alberta was also in the Turner Valley field in 1936, just west of the already known gas field. Continuing exploration efforts failed to result in another discovery and hopes for such an event were fading. Then in 1947, the Leduc oil discovery changed all expectations; it was followed by other major finds (Redwater, Pembina) which together built up the Canadian crude oil industry to its present prominent rank among Canadian industries. At this time, exploration was spreading to the whole of Western Canada and it brought finds in British Columbia, Saskatchewan, and Manitoba.

During these prolific years, Canadian crude oil reserves were boosted from 72 million barrels in 1946, to 4.2 billion in 1960, to 9 billion barrels in 1971. Production followed a similar increasing trend; from the 130,230 barrels per day mark in 1951, it jumped to 604,849 barrels per day in 1961 to be at the 1,453,900 barrels per day mark in 1971.[2]

Most of the increase in reserves and production belongs to the province of Alberta which, (see Table 1), has about 88 percent of all the known Canadian reserves of conventional crude oil,[3] and accounts for 68 percent of the total Canadian crude production. Alberta, the major Canadian crude producer, is then followed by what is here termed as the three minors--British Columbia, Saskatchewan and Manitoba. Far behind these producers are Ontario and New Brunswick, and Northwest Territories, which have a relatively negligible share of the Canadian crude industry.

Table 1

Canadian Crude Production and Reserves

	P R O V I N C E				
	Alberta	B.C.	Manitoba	Others	Sask.
Reserves (000 Bbl)	7,495,567	271,499	59,953	50,000	681,792
Production b/d	982,500	69,500	15,400	5,400	242,300

Sources: The Canadian Petroleum Association Statistical Yearbook, 1970.

Oilweek, Feb. 21, 1972, p. 61.

NATIONAL OIL POLICY

The dramatic expansion of Canadian crude oil since 1947 has profoundly altered the picture of the domestic crude supply over the years. From an almost total reliance on foreign crudes (mainly United States and Venezuela) to supply domestic needs, Canada has today reached a stage of "qualified self-sufficiency" and even of being a net exporter of crude oil. This evolution is shown in Table 2.

The term qualified 'self-sufficiency' deserves more explanation. In 1971, the total Canadian crude production very slightly exceeded the total Canadian crude oil consumption, but in spite of that, Canada remains a fairly important crude oil importer from Venezuela and the Middle East countries. The numbers

Table 2

Canadian Crude Self-Sufficiency

Year	D*(b/d)	P**(b/d)	P as % of D	Exports (b/d)	Imports (b/d)
1946	196000	21000	11	Nil	174000
1951	353000	130000	38	1000	228000
1955	537000	354000	67	45000	237000
1961	807000	605000	78	185000	365000
1965	972000	800000	82	295740	394000
1971	1410000	1453900	101.0	755000	680000

*D-Demand; **P-Production

Sources: C.P.A. Statistical Yearbook, various issues.

Oilweek, various issues.

are such that the amount of crude imported about equals the amount of crude exported (see Table 2).

The reasons for this situation are several: the crude requirements of the United States, the Canadian National Oil Policy which restricts the flow of foreign crude in some parts of Canada, and finally the availability of cheaper foreign sources of crude in Eastern Canada. At the end of the 1950's, the crude oil reserves had grown very fast in Western Canada and the rate of new discoveries was still quite high.

All the increase in "potential" production was not matched by increasing marketing progress of Canadian crude on the North American continent. The huge investments frozen in that unused capacity had an especially painful impact on the small independent crude producers whose financial prospects are very much tied to the amount of revenues they can obtain from the production of their reserves. Attempts by the independents to convince the federal government to build a pipeline to Montreal and restrict the free entry of cheaper offshore crude were unsuccessful.

This plan was opposed by the refiners of the Montreal area who would lose access to cheaper crude and also by the U.S. government. The U.S. government had been restricting the flow of Venezuela crude in the U.S. to show their discontent for some moves of the local government,[4] but it did not want these restric-

tions to throw the Venezuela economy into chaos. The continued Venezuela exports to Eastern Canada were viewed as important in maintaining the Venezuela oil industry and preventing excessive stress on the industry that could induce the government to take more extreme measures against U.S. interests.

Finally, in 1961, following the presentation of the Borden Report[5] to the federal government, the Honorable George Hees, Minister of Trade and Commerce, announced a national oil policy.[6] It was a compromise between options of the Canadian crude oil production and three ways were set to realize that goal.

First in the Ontario market, Canadian domestic crude and products should replace all foreign crudes and products, thus leaving the Montreal market open to cheaper offshore sources of crude oil. Second, refined products from foreign crudes of imported products should be replaced by products refined from Canadian crude in all of Ontario west of the Ottawa Valley (the N.O.P. line). Third, since the future rate of increase in Canadian production stemming from this new market would not be very satisfactory to Canadian producers, a special emphasis was placed on export promotion to the U.S. markets. In the view of the Canadian government, the responsibility for this export promotion rested primarily with the major producers[7] as was clearly stated by Mr. Hees in a speech to the

Canadian Petroleum Association:[8]

> While the government looks to the major integrated oil companies with refining capacity in Eastern Canada to contribute materially to this policy, it also expects that all producers, especially those having affiliations with refiners in the United States, will do their utmost to find additional market outlets. . . . We shall look for the necessary improvement during our assessment of the contributions made by each of the individual companies to the success of the oil policy.

Following the inception of the oil policy, exports of Canadian crude rose to 248,252 barrels per day in 1963, an increase of 34.60 percent over 1961. In the Ontario market, the use of domestic crude oil went from 197,200 to 265,000 barrels per day in the period between 1960 and 1963 inclusive, while the use of imported crude fell from 10,000 to 1,000 barrels per day, imported products from 17,400 to 7,000 barrels per day, and products from Quebec from 68,900 to 50,000 barrels per day.[9]

The present structure of the Canadian refining industry has been very much affected by the national oil policy. Although Southern Ontario is the major population and industrial centre in Canada, Montreal is the major Canadian refining centre. All the Ontario refineries are supplied with domestic Canadian crude, even though this is not always the cheapest source[10] and all Quebec refineries rely on cheaper foreign crude.

At the end of 1971, Golden Eagle brought on

stream a 103,000 barrels per day refinery in Quebec, Irving doubled its Saint John refinery to 110,000 barrels per day and Gulf now has a 80,000 barrels per day refinery at Point Tupper, N.S. These developments plus the further addition of a 100,000 barrels per day refinery at Come By Chance in Newfoundland, will reduce the Canadian crude self-sufficiency ratio. That is, Canada will be again a net importer of crude.

Nevertheless, this deficiency will be somewhat of an illusion since an important share of the output of these new additions to the refining capacity of Eastern Canada is for export to the United States. (Come By Chance output will be almost entirely for export to the U.S.) In fact, Canada is now producing more crude than it consumes domestically, and in view of the prospects for increased use of Canadian crude in the U.S., this trend should get even more pronounced with time.

Table 3

Refining Capacities in Canada, 1972
(barrels per day)

Province	Capacity	Province	Capacity
B.C.	127300	Ontario	392200
Alberta	171350	Quebec	578500
Sask.	65100	Maritimes	281800
Manitoba	48500	N.W.T.	2800
	Canadian Total: 1,666,550		

Source: Oilweek, June 5, 1972, p. 27.

FOOTNOTES

[1]Eric Hanson, The Dynamic Decade, (Toronto: McClelland and Stewart, 1958), p. 40.

[2]The Canadian Petroleum Association Statistic Yearbook and Oilweek, Feb. 21, 1972, p. 61.

[3]Excluding synthetic crude, i.e., Athabasca tar sands.

[4]Edward Shaffer, The Oil Import Program of the United States, Praeger Special Studies in International Economics and Development,

[5]This Royal Commission on Energy published two reports. The first one was mainly concerned with the development of prospects for Canadian natural Gas. The second was more concerned with the prospects of the oil industry.

[6]W. J. Henderson, "Canada's National Oil Policy," (unpublished M.A. thesis, University of Alberta, 1970).

[7]More will be said about the major production companies in Canada in the next chapter.

[8]Cited in "Oil in Canada," March 23, 1963, p. 29.

[9]Alan R. Plotnick, Petroleum: Canadian Market and United States Foreign Policy, (Seattle: University of Washington Press, 1964), p. 136.

[10]More evidence on this question will appear in Chapter 4.

Chapter 3

ECONOMIC AND INSTITUTIONAL CHARACTERISTICS OF THE OIL INDUSTRY

PRICE ELASTICITY OF SUPPLY AND DEMAND

The early development of the United States crude oil industry is a continuous succession of highs and lows, of good and bad times.[1] Within two years of the first commercial discovery of oil in the U.S. in 1859, while production was increasing from 1200 to 5000 barrels per day, the price of a barrel of crude fell from ten dollars to ten cents, rose to $8.06 in 1864 and fell back down to $2.41 in 1867. This period marked the rise of the Standard Empire and it is estimated that, in 1904, 88.7 percent of all petroleum dealers in the United States were buying from the group and its affiliates; this near-monoply was broken down in 1911 into 33 smaller units by the U.S. government.[2]

In the 1926-31 period, which was marked by major discoveries, the posted price of Mid-Continent crude went to $2.29 a barrel in 1926, then ranged between $1.28 and $1.45 for the next four years to plunge to $.32 in mid-1931 when oil was sold in East

Texas for as little as ten cents a barrel. These drastic fluctuations were not caused by the erratic behavior of exploration successes, since all these years showed increases in crude reserves, but by the compelling pressure on producers to produce as soon as possible the reserves they had discovered. These pressures stemmed from the basic characteristics of the oil industry--the presences of heavy fixed costs and the law of capture.

Under the law of capture, each operator in a pool can draw oil from the pool; it is not his before it flows through his pipes. Hence, it is in the interest of each operator to take as much oil as fast as possible since what he does not take can be taken by his neighbor.[3] Operating costs in the oil industry account for a relatively small share of the total costs of production[4] and these costs are the only ones that can be saved by contracting output. The consequence of that preponderance of fixed costs is a strong emphasis on volume and continuity of operation. Since sunk costs can be recovered in part or in whole only from current revenues, price can fall very low before the operator finds he is better off if he stops production. Oil supply is thus rendered very unresponsive to price changes (i.e., is price inelastic) in the short run.

On the demand side, the oil industry is also

endowed with some unusual aspects. The demand for crude oil is a derived demand, that is, a demand created by the demand for petroleum products. For some uses, they have practically no substitutes; this is especially true for gasoline, aviation turbo fuel, diesel fuel oil, and lubricants, and these account for 50 percent of the product yield of Canadian refineries in 1971.[5] In transportation and other specialized uses, liquid fuel has overriding advantages compared with potential substitutes. In other uses, like boiler fuel, many large users have equipment designed to operate readily on alternative fuels and would shift readily from oil if a change in price should favor a substitute (coal, electricity, etc.).

In short, oil products used for stationary heat and power are more likely to be in close competition with other fuels in identical uses; but in many cases, as in home heating, where equipment is usually designed for a specific fuel, substitution would be quite prohibitive and the price elasticity of the demand for oil would be very low.

In addition, since fuel and lubricants are usually a small portion of the total operating expenditure of the equipment in which they are used, including the family automobile,[6] a change in price would not tend to have much effect on the demand for

these products. An aggregate demand that fails to respond rapidly to changes in price exposes the industry that supplies it to wide price fluctuations. An inelastic consumer demand in the face of a fluctuating and inelastic supply constitutes a volatile economic setting, as was demonstrated by the examples above.

THE PROVINCES AND CRUDE PRODUCTION

Table 1 in Chapter 2 documents the level of crude oil production by provinces in Canada. Although the provinces are not the producers as such or, more precisely, the operators that extract the crude from the ground, they are by far the largest[7] owners of the resources in the provinces with the largest share of production, and as such they have unmistakable interests in the crude production. Their ownership entitles them to rents which are called royalties, that operators have to pay to be allowed to exploit the resource. These royalties are usually calculated as a percentage of the price paid to the producer for every barrel of oil extracted. In Alberta, the maximum royalty payment is 16 2/3 percent; it is 16 percent in Saskatchewan, 12½ percent in British Columbia and Manitoba.

Royalties are not the only revenues accruing to the province from the oil industry. Other revenues are bonus payments from the sale of land leases,

exploration permits, periodic fees from leases and permits, taxes on products, a share of the corporation income tax, etc.[8] The royalty is the major source of revenue and it is also the only one which is directly based on production. Since the royalty payment is an "ad valorem" form of tax, two main variables are of importance in determining the size of the government's share: the price and the physical amount produced. The powers entrenched in the provincial government enables them to establish controls to affect both variables.

The total amount of oil recoverable from a given pool is very much dependent upon the rate of extraction of crude oil. When a pool is rapidly depleted, the resulting fall in pressure may cause gas or water to come into the pool and may damage it permanently. In most pools maximum ultimate recovery is obtained when the oil is produced at or near a given pressure. This can be achieved through a given rate of production or, in other cases, where the natural drive mechanisms are not efficient enough, by artificial means that maintain or restore a given pressure (for example, injection wells). Therefore, considering the total capacity of a pool and the impact of different rates of production on ultimate recovery, maximum efficient rates of oil production (MER) are established.

In provinces such as British Columbia and Saskatchewan and Manitoba, this MER coincides with the MPR, the maximum permissible rate of oil production as established by the regulatory authority of these provinces. In British Columbia and Saskatchewan, this MPR is assigned on the basis of wells (i.e., different wells in the same pool can have different MPR), whereas in Manitoba, it is granted on the basis of pools (i.e., all wells in the same pool have the same allowables).

In Alberta, where the actual potential provincial production or peak MER capacity is about 2,108,000 barrels per day,[9] the actual production is only 982,500 barrels per day, because the MPR's as granted by the Board do not coincide with the MER's. Alberta's output is prorated to market demand. The dramatic potential price instability of the oil industry documented at the beginning of this chapter can certainly be very detrimental to any agent whose revenues are based on the oil production and this is the case for all Canadian producing provinces. It is only a more frightening outcome for Alberta than for others since it is the most important producer, oil being possibly the most important basis of its present economy and of its future. Alberta also has a potential production that could more than saturate the whole market for Canadian crude, which other

Canadian producers of lesser importance could not do. To avoid that highly undesirable outcome, Alberta has initiated a system of market demand prorationing.

Such a prorationing program was initiated in Alberta in 1950 and it is administered by the Alberta Oil and Gas Conservation Board as provided for by section 36 of the Oil and Gas Conservation Act of the province.[10] The Board has the power in the interest of conservation and equity between owners to restrict the amount of oil or gas that may be produced in the province by:

1. fixing a provincial allowable not exceeding the market demand as determined by the board,

2. allocating the provincial allowable for oil in a reasonable manner among the producing pools in the province by fixing the amount of oil that may be produced from each pool without waste to meet the provincial allowable so determined and,

3. distributing the portion of the provincial allowable allocated to a pool in an equitable manner among the wells in the pool for the purpose of giving each owner the opportunity of producing or receiving his just and equitable share of the oil in the pool.[11]

Each month, purchasers of Alberta crude oil are required to nominate for the amount of oil they wish to purchase in the following month; the sum of their nominations represents the market demand for Alberta crude oil for the month. The market demand is then adjusted to take into account the amount of oil to be produced from wells classified as marginal or incapable pools and from minor unprorated pools.

After having established the adjusted market demand each pool is allocated part of the demand on the basis of factors such as ultimate and remaining reserves. Once this has been done, any pool which has been allocated less than what is termed a floor allowance based on its depth has its allowance increased to the level of that floor allowance, this addition being subtracted from pools that received more than their floor allowance. Then the pool's allowable is divided between the wells on the basis of the amount of acreage relative to the total acreage of the pool,[12] so in Alberta, the MPR is usually smaller than the MER.

The advantages stemming from the enactment of such a scheme are manifold. First, it ensures a greater price stability by preventing gluts or scarcity of crude oil on the market for Canadian crude. This price stability then provides the province with a more predictable stream of revenues and minimizes the potential economic instability that could be induced by the fluctuations of fortunes of the oil industry in the province. Second, it helps the province to reduce the concentration of crude production.

As will be documented later in this chapter, the operating agents of the oil industry are for the main part integrated multinational corporations. They are also the main buyers of crude oil. Without the prorationing system, these might very likely be

induced to rely mostly on their own reserves, thus restricting greatly the marketing horizons for smaller, unintegrated and often domestic producers for whom a steady stream of revenues is a matter of life or death for their operation. Thus the plan may be viewed as a means to open the market to more operators by giving to each one of them a just share of the market. A greater number of operators can have a positive effect on the government revenues by inducing a more competitive bidding for the exploitation of the province's resources.

This scheme also "officializes" the leading role exerted by Alberta on the Canadian crude oil industry since Alberta appears as the only one that can meet increments in demand and is the only one that really faces the market demand. The inability of other provinces to meet increases in demand is easily demonstrated if one looks at the production trends for the producing regions in Canada over the last few years. Table 4 will show the total production of these provinces vis-à-vis their reserve position.

In spite of large increases in demand for Canadian crude over these years, the Saskatchewan and Manitoba production is now slowly decreasing and British Columbia seems to have crested. Alberta is left to absorb the total increase in demand for crude and also to offset the decrease in the total

Table 4

Canadian Oil Production Trends

Year	Oil Production (b/d)				Oil Reserves (000 barrels)			
	Alta.	Sask.	B.C.	Man.	Alta.	Sask.	B.C.	Man.
1965	503365	240517	36906	13552	5719686	661672	251822	41071
1966	554815	255392	45584	14331	6720500	696785	263784	58336
1967	630715	253532	53854	15303	7030049	725603	294246	66066
1968	684905	251038	60523	16952	7253019	720503	287246	67713
1969	764864	239469	69340	16999	7543195	688209	272282	64422
1970	892033	245169	69483	16192	7495567	681792	271499	59953
1971	982500	242300	69500	15400	NA*	NA	NA	NA

*NA - Not available.

Source: C.P.A. Statistical Yearbook, 1970.

production of the three minors. This illustrates well that British Columbia, Saskatchewan and Manitoba oil producers operate at MER(MPR=MER) whereas Alberta's producers don't (MPR$\neq$MER), which provides Alberta with an unused capacity of 1,036,000 barrels[13] per day in 1971. It should be noted, though, that this unused capacity could not be brought instantly on the market because of constraints imposed by auxiliary facilities. So the peak capacity adjusted for field and processing capacity and main line capacity is 1,320,000 barrels per day and the actual provincial crude oil operational capacity is 1,254,000 barrels per day.[14]

THE OPERATING AGENTS OF THE OIL INDUSTRY

Up until now, this discussion of the oil industry has introduced only the provinces, among those interested in crude production. As mentioned above, the involvement of the provinces in production, although real, does not consist of physically extracting the crude. This is the work of the private entrepreneurs or corporations; they bring the know-how and the money required for finding, developing, and producing the crude. It is not possible, as it was for the provinces, to present every one of these operators with their production reserves, because there are too many producers and not enough information is available. In addition, it is not necessarily relevant to the

discussion. What is of interest is to define if possible what kind of behavior is probably in their self-interest and see if the achievement of their goals is compatible with the provinces' interests.

This implicitly assumes that, somewhere, someone might have the ability to influence the crude market. If the market is a competitive one as defined in economic theory, it would be quite irrelevant to try to find those who could influence the market and make it work in their own interest. There are, in the history of the Canadian crude industry, clues to arouse such a suspicion.

During the 1950's, the Canadian crude oil industry was developing at a very high rate. Many companies got involved in production and were fighting hard to market their reserves. The Canadian market was then quite a competitive market. Many different crudes were imported in many markets and there were no administrative restrictions on the flow of oil. To gain markets, Canadian crude had to fight a hard battle and all the 1950's were marked by very frequent price fluctuations. More than a dozen times the posted prices of Canadian crude were changed.[14] From \$2.73 in October, 1950, the posted price of Redwater fell in steps to \$2.315 in April, 1952, to increase to \$2.645 in July, 1953; it was then \$2.485 in 1955, \$2.63 in 1957, \$2.52 in 1961. Then in May, 1962, the price

was set at $2.62 and remained there until December 25th, 1970, when it was raised to $2.92. Why that sudden stability?

The year 1962 was an important year for the Canadian oil industry: the National Oil Policy went into effect. From then on, all the Canadian market west of the Ontario Valley Line was a captive market for Canadian crude. Canadian crude did not have to compete with imports. This protection was expected to bring some greater degree of stability for Canadian crude prices, but this stability was total. The oil industry is constantly complaining about the increasing costs, but the price of crude remained constant for eight years while inflation was slowly eating the value of the Canadian dollar. Prices increased in the U.S., but the increases were not matched by Canadian crude prices.[16]

The only element that was to spark a price increase in Canada was the settlement of the major oil companies with the O.P.E.C. countries in 1970 which raised the price of offshore crudes. This peculiar price behavior suggested, in our estimation, that once the outside influences were removed, someone seemed to have been able to control and maintain very effectively the price of Canadian crude. But the proposition that there was really an administered price of Canadian crude is hard to prove. To find

someone in the oil industry who could affect the pricing of crude, and then try to find where his interests lie, might meanwhile be an enlightening step.

Concentration

The demand for crude is derived from the demand for the products and those who make these products are the refiners; these are the only outlets for a crude producer. A list of all the Canadian producers is not, as far as we know, available, but a list of the Canadian refiners is easily made and appears in Table 5.

Table 5

Refiners in Canada, 1972

Company	Number of Plants	%	Capacity (b/d)	%
Imperial Oil (Esso)	9	22	447,000	26.8
Gulf Oil	8	19.5	327,900	19.7
Shell Canada	6	14.6	248,000	14.9
Texaco	4	9.7	142,000	8.5
Golden Eagle	2	4.8	115,500	6.9
Irving Refining	1	2.4	108,000	6.5
B.P. Oil	2	4.8	107,000	6.4
Petrofina Canada	1	2.4	65,000	3.9
Others	8	19.4	106,150	6.4
Total:	41		1,666,550	

Source: *Oilweek*, June 5, 1972, p. 23.

What is striking from that list is the relatively small number of buyers of crude. But the above list must be modified for our purposes. Many of the above refiners do not use Canadian domestic crude since they are operating east of the N.O.P. Line.[17] A new list, including only those refineries using Canadian crude, is shown in Table 6.

Table 6

Canadian Refineries West of the NOP Line, 1972

Company	Number of Plants	%	Capacity (b/d)	%
Imperial	7	25.0	276,700	34.3
Gulf	6	21.4	179,500	22.3
Shell	5	17.8	148,000	18.4
Texaco	2	7.1	60,000	7.4
Others	8	28.6	141,650	17.6
Total	28		805,850	

Table 6 seems to emphasize what appears to be a strong concentration by four companies: Imperial, Gulf, Shell and Texaco. They control 82.4 percent of all the refining capacity west of the NOP Line. The depth of their involvement in production only is shown in Table 7. Only 29 percent of Canadian crude production comes from these four companies. In fact there are a large number of small crude producers in Canada, creating a situation whereby there are many sellers of crude but just a few buyers. So, if some operators can really affect the pricing or output of crude in Canada, they should

be found in the refining sector which lends itself easily to the exercising of some form of monopolistic power. If these major refiners are looked into, one finds many common chacteristics among them of which the most striking are their complete vertical integration and their multinational character.

Integration

Integration always seemed to be a fact of life in the oil industry. The first major oil company (Standard Oil of New Jersey) was completely integrated and when it was broken down into 33 smaller components, each of these then strove to achieve integration[18] again within their own operations.

Integration, it has been argued, is a way to dampen the extreme potential variations of fortunes in the risky business of oil. The discovery of crude,

Table 7

Company Crude Production and Reserves, 1970

Companies	Production (b/d)	%	Reserves (000 barrels)	%
Imperial	170,000	14.0	1,567,000	18.3
Gulf	92,000	7.5	580,000	6.78
Shell	67,700	5.5	485,000	5.67
Texas	26,000	2.0	(not available)	-
Total	355,700	29.0	2,632,000	30.75
Total for Canada:	1,228,090			

Source: Financial Post Card Service.

in spite of all the geological and geophysical knowledge now allowed by modern techniques, remains a risky endeavor. The only way to know for sure if there is oil is to drill and even that, because of bad drilling practices, can bypass a producing horizon. So there seems to be widespread reluctance among larger companies to gamble all their present existence and future exploration on the probability of a lucky strike. Integration then appears as a diversification of investment into more secure areas. Should the hazards of explorations be adverse, crude could be bought, refined and marketed, thus keeping the firm alive and possibly in a still healthy financial position. Revenues accruing from higher steps in the integrated chain could also be diverted below to finance new exploration.

Other arguments in favor of integration pertain to the specific nature of crude oil, a volatile product whose storage and excessive hauling could adversely affect quality (evaporation of certain lighter fractions for example). Integration then appears as a more efficient structure to handle this peculiar product. In addition, integration has often been undertaken to assure more reliable sources of supply. The investments are so huge in the oil industry that the steady flow of oil must be insured; ownership by a refiner of its sources of supply is one means of

ensuring security, long-term supply contracts is another. At the other end, integration is also used to provide assured marketing outlets. There are also special crudes that no existing refineries could be equipped to handle profitably; it then pays the producer to build his own adapted refinery, thus increasing the economic value of his crude. Such were the heavy crudes in Saskatchewan, which few refineries could handle profitably. A specially built refinery was set up in Minneapolis, St. Paul, to use this crude. This example is useful to show that such situations can occur, but in this case the building of the Great Northern refinery was the result of inter-company agreements and not the result of an intra-company decision.

From the particular nature of the province's oil revenues, it is quite clear that, once the amount of oil to be produced is set, the highest possible price[19] will produce the largest amount of revenues. But provinces as such do not set prices. The price is set in the transactions between the firms involved in the different steps of the oil industry. Refiners want to acquire crude and in view of the market situation, they can agree with the producers on the price that will be paid for the crude. The provinces as such are not directly involved in these transactions, although their policies can certainly influence the outcome.

For the producer who is interested in marketing his crude, the marginal cost of producing an additional barrel of oil is not zero but some positive number. Many costs are involved for him to have an additional barrel of oil, whether they stem from exploration, development, secondary recovery, lifting, or any kind of activity whatsoever.[20] From that point of view, it is very likely that both the provinces and the producers would not maximize their returns at the same price.

In Figure 1, P-D is the demand curve for Canadian crude, P-MR the marginal revenue curve, and MC the marginal cost curve to the producers. For the provinces, the price P_2 will maximize net revenues as MC=0 for the provinces; but for the producers, a price P_1 would maximize, instead of P_2, because $MC \neq 0$ for them. Two different outputs are also involved, Q_1 and Q_2. The actual demand curve today is widely assumed to be quite inelastic.

The Canadian market west of the NOP Line is a captive market and the amount of exports to the U.S. is subjected to a quota. The situation as shown in Figure 2 then occurs.

The section AB of Figure 2 would correspond to the range of prices where no penetration into the U.S. market is possible because of too high prices. Only the Canadian captive market is served with an

Figure 1

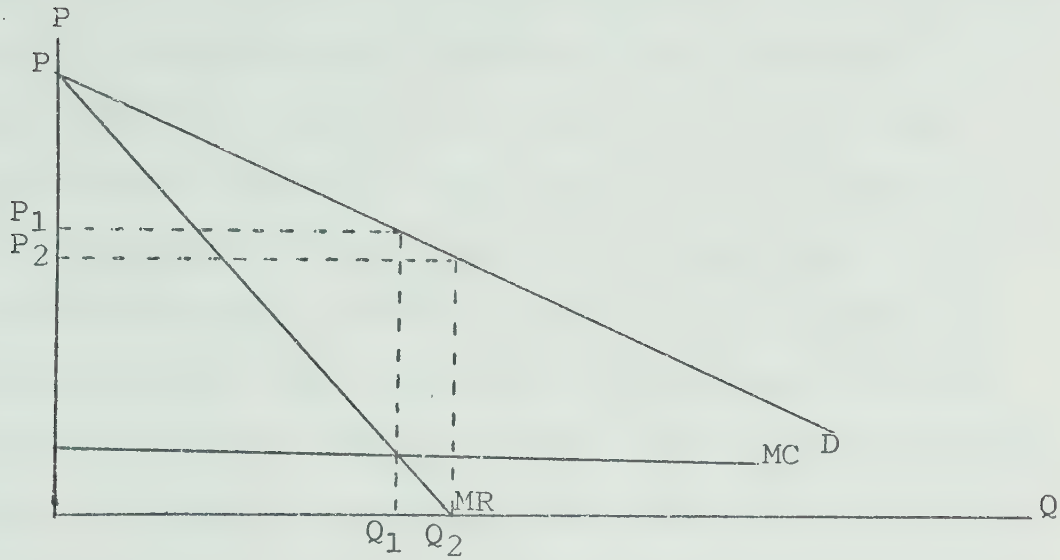
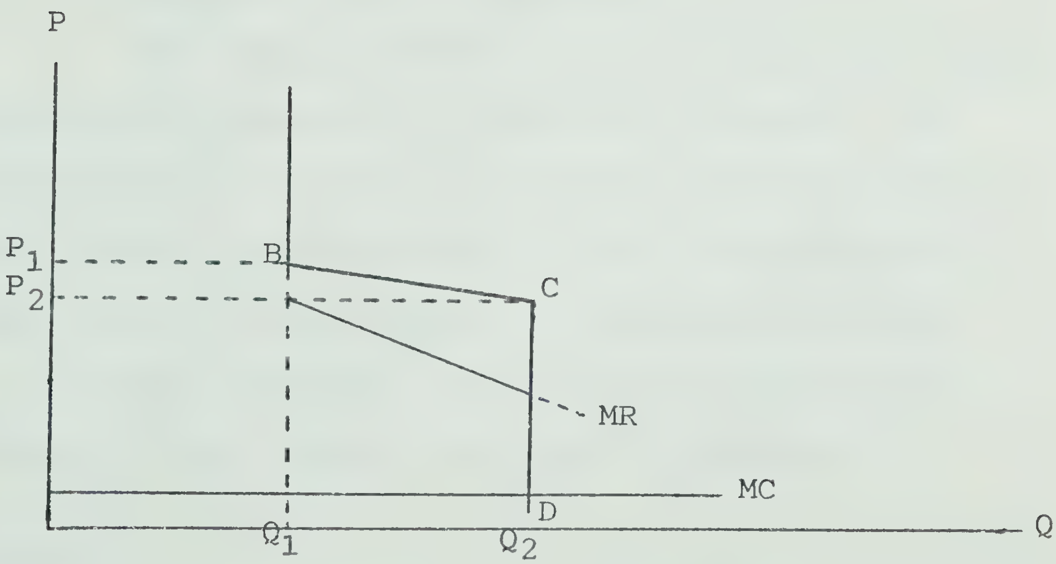


Figure 2



<u>Note</u>: The government and the companies do not essentially face the same demand curve since the demand for the government is a derived demand from the companies' demand. Since government revenues in the form of royalty payment is a fixed percentage of the companies' revenues, the points of net revenue maximization for the government shall be for the same amount of output if either curve is used.

amount $O-Q_1$. Then as prices fall below P_1, penetration into the U.S. market begins and when the price reaches P_2, the maximum amount allowed by the quota Q_1-Q_2 is being exported and for any price below P_2, no more crude can be sold (at least not until the price falls low enough to be competitive with other crudes east of the NOP Line). Given a curve MC as the marginal cost curve for the producers, in this case a similar price P_2 would maximize revenues both for the provinces and the producers (assuming that the section B-C of the demand curve is elastic). Therefore, should the producers behave competitively, their objective and that of the provinces will be compatible.

Are the transactions between sellers and buyers of crude really made in a competitive manner? The high degree of concentration in the refining sector, and the particular character of the firms involved, cast doubts in that respect. For various reasons it could pay the firms to exert some power on the market: these reasons will now be considered.

Taxation

A country's tax structure can substantially affect the pricing policy of an integrated firm; special tax concessions or allowed deductions at some level can favor a higher or lower rate of profits at that given step of the integrated chain. In Canada, all firms with taxable income over $35,000,

pay a 50 percent corporation income tax to the government. But in the Canadian tax system, there is a special treatment for firms involved in resource extracting industries.

A depletion allowance is granted in some circumstances to firms receiving income from oil and gas production in Canada. This allowance permits a taxpayer to deduct a fixed percentage of his net income from the production of oil and gas in computing his aggregate income for tax purposes. Of the three types of oil and gas depletion allowances, one is of interest to our purpose: the operator's depletion allowance.

An operator is defined as a taxpayer who has an interest in the proceeds of production from an oil or gas well under an agreement providing that he shall have the profits remaining after deducting the costs of operating the oil or gas well.[21] This operator is permitted to deduct, in calculating his taxable income, an amount equal to 33 1/3 percent of the net profits in a taxation year "reasonably attributed to the production of oil and gas resources operated by the taxpayer."[22] Net profits are the aggregate of the profits derived from the operation of the oil resources, once all deductions allowed under the Income Tax Act have been subtracted. This allowance is available to all oil producers in Canada.

In addition, if a corporation "passes" the "principal business test," it is allowed to deduct its drilling and exploration expenses from its income for the year from any source.[23] Although this option is open to all producers having their main business in oil, it remains a quite useless feature to most of them since many have only one source of income. Only the integrated oil companies who all pass the principal business test and have income from many sources--production, refining, transportation, and marketing--can take full advantage of the provision.

Broadly speaking, depletion allowance is not available until a corporation operating mineral resources is in a taxpaying position, as mentioned in the Canadian Tax Foundation book on page 196:

> It would be fair to state that the large majority of companies whose operations consist solely of an exploration and production nature have not yet attained a taxpaying status and accordingly have never obtained depletion allowances. . . . A somewhat different situation exists in the case of integrated oil companies, that is, companies engaged in refining and marketing as well as the exploration and production phase of the industry. A number of these companies are in a taxpaying position as a result of having utilized their drilling and exploration expenses against their refining and marketing income. These companies that are in effect paying a tax rate of 33 1/3% (50% of 66 2/3%) on their production income after deduction of their current year's drilling and exploration expenses.

The Canadian tax treatment then seems biased toward the integrated or against the non-integrated

operator since they (the integrated operators) can write off all expenses immediately against revenues from other sources. And it appears in the interests of the integrated operator to show profits only at the production level where the tax rate is 33 1/3 percent rather than the potential 50 percent if profits were shown at other levels.

Depending on the strength of an integrated firm at each level of the integrated chain, some specific form of pricing could then tentatively be enforced by the firm. Should a firm be very strong at both the refining and the marketing levels, but rather weak at the production stage, it seems likely that an incentive exists to have a higher price for crude so as to have enough revenue to ensure that all the desired amount of profits can totally be transferred to the production stage for tax purposes.

If such a situation was prevalent in the Canadian case, it would support a very common belief that the Canadian refiners try to maintain a profit squeeze at the refining stage as a barrier to new entries in refining.[24] It is far from obvious that this is the case in Canada, since the production of the four majors, although not as large as their refining needs, is by no means a negligible fraction of their needs (about 35 percent).

A related case in which it would pay an integrated firm to have a high price for crude has been

studied by De Chazeau and Kahn,[25] but their conclusions do not apply in the Canadian case because, as opposed to the United States, where the depletion allowance was 27½ percent of gross income, the depletion allowance is calculated on net income. This last tax treatment does not lend itself to a simple model study because of all the deductions and expenditures available.

International Character

The four major oil firms in Canada are not only integrated, but also are parts of multinational corporations. That is why the proposition that the Canadian firm tries to maximize profits in Canada is not a clear-cut conclusion. Also, it must be noted that the Canadian part of the operation of these multinational corporations is relatively small.

Table 8

Canadian Operations vs. World Wide Operations (b/d)

Company	Canadian Production	Canadian Ref.*	World Prod.	World Ref.*
Standard Oil N.J.	140000	430800	4665000	5270000
Gulf	92000	201400	3057000	1736000
Shell	67700	241500	3759000	5042000
Texaco	26000	131000	2987000	2719000

*Ref. - Refining Capacity

Sources: Financial Post Card Service.
Energy Memo, Petroleum Dept., First Nat. Bank, Jan. 1972; and Oilweek, June 5, 1972, p. 23.

As in any other firm the multinational probably tries to maximize some parameter, whether it is profits or sales with a profit constraint etc. In any case, whatever the corporation maximizes, it does so for its operation as a whole and not independently for all its components or branches. For example, maximizing profits for firm A might involve suffering losses for its operation in country B. It could be so, because of a different tax structure between countries; it could then be more rewarding to show profits in countries with lower taxes. Maintaining a low return plant in an area can be justified by many reasons, such as presecuring the supply of some resource which could be needed in the future, barriers to entry, etc.

More insight into the most likely motivations of these multinational corporations could be provided by a more complete look to their whole world wide operations. This is the purpose of Table 9. From Table 9 it is possible to calculate the Canadian self-sufficiency ratio for Imperial Oil (32.4 percent) and Gulf (45.6 percent). These low values contrast very heavily with the much higher self-sufficiency ratio achieved by the parent company on a world wide basis as shown in Table 10.

Much of the Canadian production is exported to the U.S. In 1971, 756,000 b/d were exported to U.S. markets. But Canada is obviously not the only

Table 9

Integrated Oil Companies; World Wide Self-Sufficiency (1960 and 1970)

Companies	U.S.A. & Canada	Other Western Hemisphere	Eastern Hemisphere	World Wide 1970	Average 1960
Standard Oil (N.J.)	80.2%	124.3%	77.3%	88.5%	76.8%
Gulf	82.2%	101.5%	334.4%	176.1%	117.4%
Texaco	83.2%	59.6%	152.3%	109.9%	95.6%
Shell (excl. U.S.A.)	30.1%	104.0%	71.5%	76.1%	70.3%
Shell (U.S.A.)	67.1%	-	-	67.1%	66.2%
Average	76.2%	105.4%	108.2%	97.9%	88.9%

Source: Energy Memo, January 1972, First National City Bank, New York.

Table 10

Self-Sufficiency Ratio for Major Companies in Canada: (1971)

Companies	Canada	World Wide
Standard Oil	32.4%	88.5%
Gulf	45.6%	176.1%
Shell	30.1%	75.0%
Texaco	19.0%	109.1%

Table 11

Origin of Crude Exports to the U.S., 1971

Area	Amount (b/d)
Latin America	333,000
Canada	765,000
Eastern Hemisphere	576,000

Source: Oil and Gas Journal, January 31, 1972, p. 93.

crude exporter to the U.S. A list of these appears in Table 11.

Another interesting facet of crude exports to the U.S. is the apparent disinterest of the major Canadian oil firms in importing Canadian crude. In the Oilweek of June 5, 1972, there is, on page 26 a list of U.S. refineries using Canadian crude. Out of the 46 refineries importing Canadian crude, only six are owned by the four most important Canadian refiners and they usually nominate for small percentages of this whole requirement (except for those refineries in the Puget Sound area which rely almost completely on Canadian crude).

A plausible explanation for this might be that the majors do not feel inclined to import from areas where they own a relatively small percentage of the total production, as is the case in Canada. A given increase in crude exports to the U.S. for example is likely to be more rewarding to them if it comes from any area but Canada where very little of the increase would revert back to them compared to what they can expect from other areas. In addition, the prorationing scheme makes it impossible for any buyer to select a specific seller. An expansion of Canadian output can then be felt as more revenues to a lot of small competing producers.

Since the major companies cannot directly

affect crude output in Canada, it then seems very reasonable that they would prefer to see a lower price for Canadian crude than what could be obtained by competition with other crudes. A higher price would seemingly be equivalent to a subsidy to the smaller producers. The majors will have to pay more for the crude they need at their own refineries while very little of the increased value of the crude produced would revert to them. With the monopolistic position enjoyed by the majors in Canada at the refining level, the ability to affect price exists and actions to affect it are within the realm of possibility.

Another aspect which should be noted is that the prorationing scheme in effect in Alberta probably affects the major companies more than the smaller producers. In all prorationing schemes, the pools which usually are the most affected are the best, those with the highest potential rate of output per well and the bigger reserves. The share of ownership of the major companies in such superior pools seems to be greater than their share of the inferior pools, meaning that proportionately more of their reserves are tied up underground than for the smaller producers. This could then appear as an additional incentive to the major companies to lower the price of crude in Canada. Table 7 (p. 27) shows in numbers what is said above. We see that Imperial accounted

for only 14 percent of total Canadian production in 1970 though it owned 18.2 percent of the reserves; Shell breaks about even and Gulf seems slightly favored. Is this downward pressure of the price of Canadian crude effectively enforced by the major companies?

An answer to such a question is extremely difficult. The best that can probably be expected is to check if the actual market condition would allow a reasonable suspicion to that effect, given the parameters that can be observed. To do so, the best way is probably to determine the demand curve facing Canadian crude by calculating the landed prices of all competing crudes in all markets already open or potentially open to Canadian crude, and see if the actual price of crude is the highest possible in the present conjunction. This will be the topic covered in Chapter 4. But, before we get to that topic, let us look at the actual markets of Canadian crude.

MARKETS

The development of markets for Canadian crude followed several stages. In the first stage of market growth, crude oil from Alberta was mainly used for local provincial consumption in the two main refinery centres, Edmonton and Calgary. A second stage started with the building of the Interprovincial pipeline eastward through Regina to the head of the Great

Lakes in Superior, Wisconsin, in 1951.[26] From this point oil was shipped by tankers to points of consumption further east to Sarnia. Alberta oil then competed in the Prairies and western part of the Great Lakes. A new stage of market growth was set with the operation of the new Trans Mountain Pipeline in 1953; oil from Edmonton was then sold in the Vancouver Market and subsequently to refineries at Ferndale and Anacortes in the Puget Sound area of Washington State. At about the same time the Interprovincial line was extended to Sarnia.

Having reached such distant centres as the Puget Sound area and Sarnia, the Alberta oil industry entered a stage in which the number and size of the markets within the limits of its domestic marketing orbit were steadily increasing. By a further eastward extension of Interprovincial in 1957, Toronto became the biggest market served with Canadian oil. In 1963, an additional eastward extension of the same pipeline brought Canadian crude to Buffalo. In 1968, a new section of the interprovincial system was extended southward to Chicago which is still today and will certainly be for a long time the biggest market available to Canadian crude.

On another front the Rangeland pipeline, owned and operated by Hudson's Bay Oil and Gas, has been exporting increasing amounts of Canadian crude

into the United States PAD district IV.[27] Through that outlet, Canadian crude is now being sold as far as Arkansas, Kansas, close to the Oklahoma border.

To date, Canadian crude has completely replaced all foreign crudes in all of Canada but that east of the NOP line. The development of export markets has had to be confined to the United States since Canadian crude, because of its landlocked position, has little opportunity to compete with Middle East and other crudes in the world market. The fuel hungry United States market with its slightly decreasing reserves, constant production and fast rising demand certainly offers great hope for ever increasing marketing opportunities for Canadian crude.

PRICING STRUCTURE

The dominant position enjoyed by Alberta vis-à-vis its producing neighbors, as emphasized earlier in this chapter, made inevitable the price leadership role assumed by Alberta in the pricing of crude in the different markets where Canadian crudes, from different origins, compete together.

The setting of the Canadian crude oil industry is an oligopolist one since there are very few producers (four are considered), where one acts as a price leader because of its dominant position (Alberta) and the others as price followers. Such models have been

Table 12

Canadian Crude Exports to the U.S.

Year	District I	District II	District IV	District V	U.S. Prod.
1967	54,500	154,000	18,600	186,000	8,810,000
1968	58,228	213,520	26,634	164,100	9,095,000
1969	72,208	241,299	34,193	207,650	9,238,000
1970	78,960	322,980	49,377	218,502	9,637.000
1971	Canadian Total - 756,000				9,546,000

Sources: C.P.A. Statistical Yearbook.

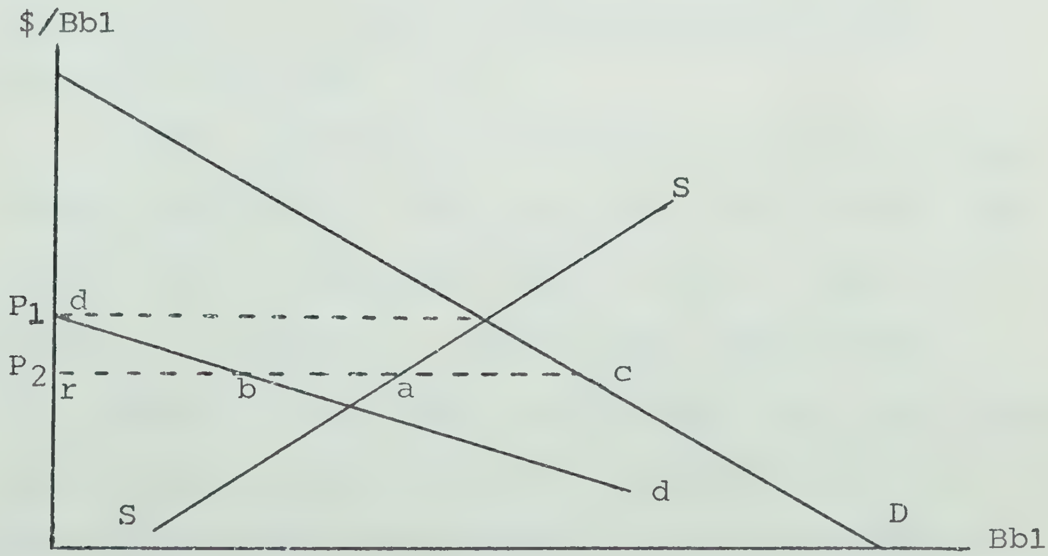
The Crude Petroleum and Natural Gas Industry, Statistics Canada, publication number 26-213, 1967.

Oil and Gas Journal, January 31, 1972, p. 87.

studied by traditional economic theory,[28] and in very few cases in economic studies it is possible to find a model that can be applied so strictly to a real world example as the price-leadership-by-a-dominant-firm model to the Canadian oil industry.

In this model, the dominant producer sets the price for the industry, allows the small producers to sell all they wish at that given price, and supplies the rest. Each small producer then operates in an environment in all ways similar to perfect competition. It cannot affect price and can sell all it wants at the current price. It then faces a perfectly elastic demand curve at the going price. Let us draw first a market demand curve DD and a supply curve for all small producers combined, SS; the latter is obtained by summing horizontally the marginal costs curves of all

Figure 3



the small producers, giving the amount that they will all together supply at different prices. The curve DD then shows the total amount of Canadian crude that can be sold at different prices, and SS shows how much the smaller producers will supply at different prices. To find the demand curve faced by Alberta, one only has to take the horizontal differences between these two curves (DD-SS), which will give dd. So, at a price $p=p_1$, Alberta will not sell any crude. At a price p_2, Alberta will be able to sell an amount equal to rb or ac since by construction ac=rb. In the real world, the curve SS is likely to be quite inelastic because of the inherent nature of the oil industry. The price of a barrel of crude will have to fall drastically before the output of the smaller producers will be significantly affected. Production costs are a very small element of total costs, i.e., the marginal cost of producing an already discovered barrel is very small.[29]

The applicability of the above model has been clearly established during the 1956 Suez crisis. The closure of the Suez Canal had then put a very hard squeeze on shipments of Middle East crude to the U.S. Crudes of the western hemisphere were then called upon as replacements. In 1956 and 1957, Canadian exports of crude to the United States rose sharply but since the surge was not in the "normal"

course of market trends, they declined very sharply when the affair was settled and shipments of Middle East crude returned to a more normal pattern. Table 13 shows the impact this surge in Canadian exports and production had on each of the Canadian producing provinces.

Facing a decreasing demand for Canadian crude, Alberta had to curtail its 1956 production by about 25 percent in 1958 while at the same time Saskatchewan's output more than doubled and B.C.'s more than tripled. The decrease in Manitoba's output after 1957 is in no way related to an unfavorable demand for Canadian crude but to declining reserves; it had to wait until 1968 to get a level of output equivalent to 1957. This example clearly shows the insensitivity of the small producer's output to variations in demand; they operate exactly as if they were in a perfectly competitive setting, selling all they can at the ruling price.

Alberta, the dominant firm, sells crude in many markets, the major one being in the Chicago-Sarnia-Toronto-Detroit areas. Let us say that Alberta crudes sell in this market at price P. Then according to what was said above, the smaller producers should price their crude such that it sells at the same price as Alberta's in that major market. This proposition can be tested easily in the Canadian case, but before doing so, some additional concepts should be classified.

Table 13

Provincial Crude Oil Production, 1955-61, (b/d)

Province	1955	1956	1957	1958	1959	1960	1961
Alberta	309,263	392,733	374,958	308,376	353,121	356,740	432,361
Saskatchewan	31,006	57,588	100,489	122,263	129,979	141,716	153,037
British Columbia	2	406	946	1,404	2,373	2,369	2,789
Manitoba	11,358	15,810	16,684	15,970	13,852	13,017	12,275
Exports to U.S.	40,641	117,235	142,913	76,662	91,518	114,456	184,939

<u>Source</u>: C.P.A. Statistical Yearbook.

So far in this discussion, all reference to crude has, in effect, been to some kind of homogeneous product produced at different locations. This is not exactly so. Crude oil is a liquid mixture of paraffins and other hydrocarbons with a wide range of molecular weights and containing varying amounts of impurities such as sulphur, nitrogen, and other elements. It ranges in specific gravity (relative to water) from about 0.7 to nearly 1.0 with varying degrees of volatility.

The oil industry does not use the specific gravities of crudes to classify them but an analogous concept in which the units are called degrees API (API^o, American Petroleum Institute); the range is usually from 50 to nearly 10 API^o for heavier crudes.[30] Lighter crudes (higher API) containing more of the lighter fractions of the hydrocarbon chain are usually more valuable to the refiners, whose products consist of gasoline in the proportion of 40 percent; so they will be ready to pay a higher price for a lighter crude.[31] The Platt's Oilgram Price Service shows different price schedules for gravity differentials in the U.S. but the most common practice is to calculate a differential of 2 cents per degree API. There are in addition what are called penalties, charged in the case of crudes containing more than a given amount of sulphur (sour crude vs. sweet crude).

Once these adjustments are taken into account, only then can crudes with similar gravity and sulphur content be considered as equivalent. So care must be taken when price comparisons are made that the crudes considered really are equivalent and, if not, that the necessary corrections are applied to make the comparison meaningful.[32]

For the following test, (Table 14) two crudes have been chosen; Alberta's Redwater and Saskatchewan's Steelman. Redwater's gravity is rated at 35°API and

Table 14

Cost Estimation of Two Crudes-Delivery-Sarnia

	Redwater 35°API	Steelman 33-39°API
Wellhead Price	\$2.92[a]	\$2.945
Gathering Allowance	-	.015
Gathering Charge	0.05	0.080[c]
Pipeline Allowance	-	0.015
Pipeline Tariff	-	0.040[c]
Trunk Pipeline Tariff[b]	0.50	0.373
Landed Costs (Sarnia)	\$3.47	\$3.468

[a]At field costs.

[b]Through interprovincial pipeline.

[c]Via Westpur Pipeline to Cromer.

Source: Data is from regulatory bodies' publications of both provinces, CPA Statistical Yearbook, and Financial Post Card Service.

Steelman's is rated in the 33°-39°API range. (The latter pool involves different producing horizons with different gravities; let us assume that an average 35°API is not too far off for its gravity.) The selected market for delivery of both crudes is Sarnia. Computations go as shown in Table 14.

Terminology in Table 14:

1. Wellhead Price: there is usually a posted wellhead price for every field which is published in many specialized reviews or journals. This price, unless otherwise specified, does not usually contain the price of gathering the crude within the field or moving to some point.

2. Gathering and Pipeline Allowances: these are deductions (usually ½%) set to cover what is termed "unavoidable transportation losses."

3. Gathering Charge: this is the tariff charged to gather the crude within the limits of the given field and move it to one common outlet at the "entrance" of the field.

4. Pipeline Tariff: it is a price charge to move a crude from the limits of a field (from the outlet of the gathering system) to some destination for on-the-spot use of a connection to a major transportation system.

5. Trunk Pipeline Tariff: price charged to move crude through a major transportation system.

6. Landed Costs: this is the total cost paid by the buyers of the crude at the delivery point.

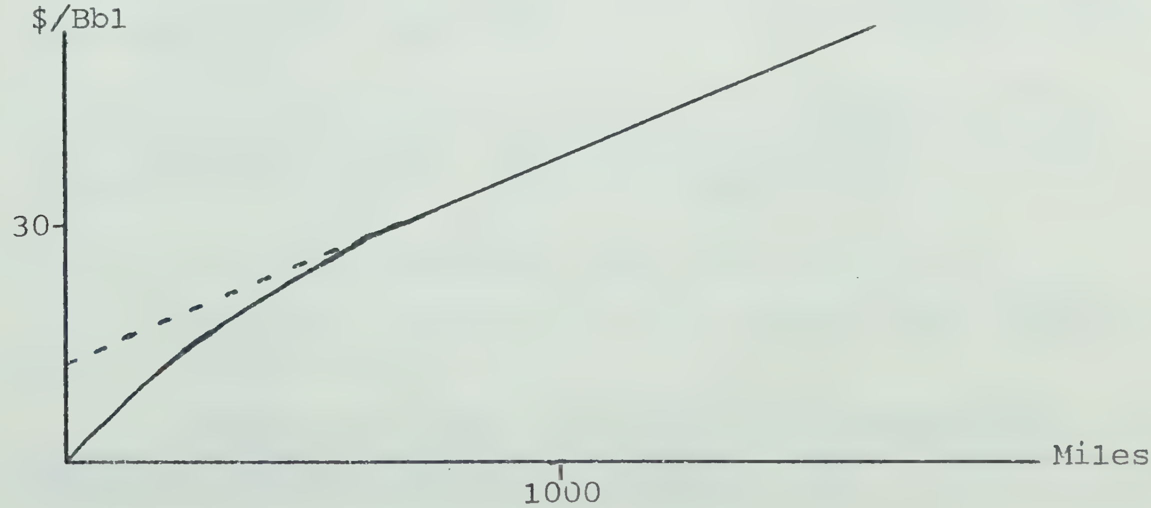
All the above information is usually given in dollars or cents per barrel. As expected, the price of both crudes delivered at Sarnia is quite similar; the similarity appears as another example of Alberta's price leadership. Given the tariff schedule of the

interprovincial pipeline and the price equalization of different (by origin) crudes in the major market, further implications of the crude price structure through Canada can be obtained. The tariff schedule of the interprovincial pipeline has been drawn in the graph in Table 15 from information obtained on the Company Card in the Financial Post Card Service. Two different points of origin for the crude have been considered (Edmonton and Cromer) and, as expected, they overlap perfectly.

Table 15

Tariff Schedule of Interprovincial Pipeline

To	From Edmonton (cents)	(miles)	Cromer (cents)	(miles)
Regina	20.7	440	-	-
Gretna	29.5	775	11.4	180
Superior	36.3	1100	22.5	505
Detroit	53.0	-	42.3	-
Chicago	45.0	1570	34.0	975
Sarnia	48.0	1750	37.3	1155
Toronto	51.0	1925	40.3	1330
Buffalo	53.0	1975	42.3	1380



Source: Financial Post Card Service.

The tariff structure is obviously not a linear function of distance, at least not on the whole span considered. It has the form of a decreasing exponential curve. (It has a linear behavior beyond the 700 or 800 mile mark.) If the schedule were linear, all crudes would have the same price in all markets where they are sold, but due to the nature of the schedule, they do not. Looking eastward from Alberta, in all markets within the main market, crudes from Saskatchewan and Manitoba will undersell Alberta's; and in Manitoba, for example, Alberta crude is undersold by Manitoba's even if both will have the same price in the middle Great Lakes area.

FOOTNOTES

[1] Melvin G. de Chazeau and Alfred E. Kahn, Integration and Competition in the Petroleum Industry, Petroleum Monograph Series, Vol. 3, (New Haven: Yale University Press, 1959). The authors give an interesting summary of this story in Chapters 4 and 5 of their work.

[2] George S. Gibb and Evelyn Knewton, The Resurgent Years, 1911-1927, (New York: Harper Bros., 1951), p. 8-9.

[3] Paul Davidson, "Public Policy Problems of The Domestic Crude Oil Industry," American Economic Review, (Vol. 53, March, 1963). Note part 1 where he considers the short-run aspect of production decisions.

[4] De Chazeau and Kahn, op. cit., p. 67.

[5] Oilweek, "Product Yield of Canadian Refineries," June 5, 1972, p. 34.

[6] Cassady and Jones, The Nature of Competition in Gasoline Distribution at the Retail Level, (Berkeley: University of California Press, 1951).

[7] Eric Hanson, op. cit., p. 185.

[8]A new scheme has just been enacted (August, 1972) in Alberta where a tax is now levied on underground reserves; this emphasizes the fact that ownership of the resource is not necessary for the government to get revenues.

[9]Province of Alberta, Oil and Gas Conservation Board Reserves Report, 1972.

[10]Stella Thompson, "Prorationing of Oil in Alberta," (unpublished M.A. thesis, University of Alberta, 1968).

[11]"Oil and Gas Production and Taxes," Canadian Tax Foundation, 1963, p. 105.

[12]Stella Thompson, op. cit., p. 59-61 incl.

[13]Peak MER (2,108,000) minus Actual production (982,500).

[14]Oil and Gas Conservation Board Reserve Report, VI-18.

[15]Alberta Oil and Gas Conservation Board: Summary of Monthly Statistics, "The Oil and Gas Industry," in every annual issue, the posted prices are reported in the last pages with all changes that occurred during a given year.

[16]Twentieth Century Petroleum Statistics, (Dallas, Texas: Degolyer and MacNaughton Co. Ltd., 1971), p. 63.

[17]See Chapter 2 on National Oil Policy.

[18]De Chazeau and Kahn, op. cit., p. 86 ff.

[19]Note: the marginal cost of producing an additional barrel of oil to the province is zero; user's costs are not considered.

[20]On the problem of cost estimation in the oil industry, see Wallace P. Lovejoy, Paul T. Homan and Charles A. Galvin, Problems of Cost Analysis in the Petroleum Industry, (Dallas: Southern Methodist University Press, 1964).

[21]Canadian Tax Foundation, op. cit., p. 160

[22]Ibid. p. 188.

[23]Ibid., p. 176.

[24]On barriers to entry in the oil industry, see Eastman and Stykolt, The Tariff and Competition in Canada, (Toronto: Macmillan of Canada, 1967), p. 324 ff.

[25]De Chazeau and Kahn, op. cit., p. 222, have used a simple model to verify what level of self-sufficiency (77 percent) is needed for an integrated producer to benefit from an increase in the price of crude.

[26]Financial Post Card Service.

[27]The entire United States is divided into five administrative districts which were the districts used for petroleum administration during World War II. They are divided as follows:

a. district I East Coast: Connecticut, Delaware, Florida, Georgia, Maine, Maryland, New Jersey, New York, North Carolina, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia, and West Virginia.

b. district II North Central: Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee and Wisconsin.

c. district III South Central: Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas.

d. district IV Rocky Mountain: Colorado, Idaho, Montana, Utah, Wyoming.

e. district V West Coast: Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington.

[28]Richard H. Leftwich, The Price System and Resource Allocation, (New York: Holt, Rinehart and Winston, 1952), (Revised edition), p. 245.

[29]The model is a short-run model.

[30]$$API^{o} = \frac{141.5}{\text{specific gravity at } 60^{o}F} - 131.5.$$

[31]For a discussion of the realism of the usual practice of a differential of x cents per API^{o}, in the face of new modern refining techniques, see Petroleum Press Service, (December 1969), p. 443.

[32]In Canada, Manitoba and Saskatchewan crudes are generally heavier and have a higher sulphur content than Alberta's.

Chapter 4

LANDED COST CALCULATIONS

The purpose of this chapter is to discuss the demand curve for Canadian crude oil.

Canadian crude is obviously not the only crude available in North America; it has, in fact, to compete in most markets against U.S. domestic and offshore crudes from Venezuela, the Middle East, and the Far East. All of these crudes can be, and often are, sold in most of these markets. They can easily be shipped by tankers, and, once on the continent, be carried through a complex and elaborate pipeline system.

Two main reasons can prevent their entry in some markets. First, there is the simple economic reason: long pipeline hauls can make their price uncompetitive; and, second, there exist government policies regulating the flow of crude in some areas, as is the case in Canada west of the N.O.P. Line.

In establishing the demand curve for Canadian crude, it is very hard to account for all non-economic factors affecting the flow of crude. Such a curve might not even provide much help in terms of a better understanding of the prevailing market conditions. A more fruitful approach can probably

be obtained by postulating the hypothetical situation of complete free flow of crude in all North American markets, so that the only factor affecting the flow of crude in any one market is its price competitiveness. Hopefully, adjustments can be made at a second stage to account for any policy constraints or other non-price factors.

SOME CONCEPTS

Markets

An acceptable definition of markets, whether actually or potentially served by Canadian crude, must be provided. Two main assumptions have been used. First, the refining capacity of a region will be accepted as its demand for crude. This approximation will tend to overestimate the latter. During the first half of 1972, the demand for crude in Canada was at 90 percent of the refining capacity[1] and in the United States it was 92 percent.[2] Second, the demand for crude within every market is inelastic. The latter has been estimated at -0.10 in a submission presented to the Cabinet Task Force by the Standard Oil Company of New Jersey.[3]

In Canada, six different markets are identified as shown in Table 16.

The definition of U.S. markets is a more difficult problem, not so much with respect to their

size and geographical location, but in the determination of their import capacity. The complication is that maximum self-reliance appears to be the main target of U.S. policy on the grounds of national security.

Among other things, the Cabinet Task Force report states:

> We interpret the statutory reference to the capacity of the United States to meet national security requirements as implying a primary objective of protecting military and essential civilian demand against reasonably possible foreign supply interruption that could not be overcome by feasible replacement measures in an emergency . . . It is evident that another primary objective is to prevent imports from causing a decline in the petroleum sector of U.S. industry that would so weaken the national economy as to impair national security.[4]

An alternative approach to definition of the U.S. market was found in the following approach to market definition. It is assumed that in every state, local production cannot be displaced, so that the total import capacity of a region will be given by its total refining capacity minus its production.

Table 16

Canadian Markets

Name	Capacity (b/d)
Vancouver	127.300
Prairies and N.W.T.	287,750
Sarnia	220,800
Toronto	171,400
Montreal	578,500
Maritimes	281,000

Source: Oilweek, June 5, 1972, p. 27.

This more restrictive definition could be regarded as a situation of "free competition" between imports, implicitly recognizing the fact that U.S. total production cannot be affected as a whole although the pattern of distribution of that production could be changed, i.e., the interstate flow of oil can be reoriented.

This treatment consists in fact in applying to every state the same procedure that the U.S. oil administration uses in district V, where the quota of imports is set at the difference between estimated demand and estimated supply. In other districts, the import quota is set at a given percentage (12.2 percent) of estimated production in these districts.[5] This procedure also minimizes transportation costs for crude.

Such a procedure would certainly result in inconsistencies when the major producing states were considered, but this problem will be avoided by including in the analysis restrictions on the amount of Canadian imports to the U.S.

The peak MER crude production capacity for Canada in 1972 is shown in Table 17.

Subtracting the total Canadian refining capacity west of the N.O.P. Line (807,250 b/d), this leaves a potential 1,623,550 b/d of exports to the U.S. The import requirements for the U.S. have been around

2,071,000 b/d for the first half of 1972,[6] and are expected to be always increasing over time, in view of their decreasing reserves and loss of unused capacity.[7] So, the Canadian export potential cannot satisfy fully the U.S. import market. Thus any contraction of U.S. output is prevented, and there is ample flexibility for the reorientation of the U.S. domestic flow that would be disturbed by an increased amount of Canadian exports. In addition, the major U.S. producing area, district III, will not be considered in the market study, nor will be district I (except Buffalo) since there is no connecting pipeline with Canadian crude outlets. The crude deficiency in districts II, IV, V, the closest markets for Canadian crude, is more than enough to exhaust Canadian potential export capacity. The markets considered are listed in Table 18.

Table 17

Canadian Peak MER Production

Provinces	Production
Alberta	2,108,000
Saskatchewan	235,000
British Columbia	68,300
Manitoba	13,900
Others	2,600
Total	2,430,800

Source: Oil and Gas Journal, April 17, 1972.

Alberta Oil and Gas Conservation Reserve Report.

Table 18

U.S. Markets

District	Name	Ref. Cap (b/d)	-	Domestic Prod. (b/d)	=	Potential Imports
V	a. Puget Sound	306,000		-		306,000
	b. San Francisco	566,000		987,000		714,900
	c. Los Angeles	1,135,000		-		-
						1,020,900
IV	a. Billings (Mont.)	121,900		95,000		26,900
	b. Denver (Colo.)*	45,900		74,000		25,000
	c. Salt Lake City (Utah)	117,100		64,000		-
	d. Casper (Wyo.)	137,500		424,000		-
						51,900
II	a. North Dakota	55,000		59,000		-
	b. Nebraska	5,000		29,000		-
	c. Minnesota	134,500		-		134,500
	d. Wisconsin	51,000		-		51,000
	e. Oklahoma (Tulsa)	465,000		598,000		-
	f. Kansas 1.El Dorado**	291,000		215,000		244,000
	2.Kansas City	168,000		-		-
	g. Michigan 1. Detroit**	92,600		32,000		124,000
	2. Rest (Bay City)	64,000		-		-

*Colorado is more than self-sufficient and Utah is not; but Colorado's production is very close to Utah and is in fact used there, so Utah is then considered as self-sufficient and Colorado gets potential imports equal to the combined deficiency of both states.

**Some states have been divided into two separate markets. When the concentration and geographical location of the refining capacity seemed to make such a procedure more realistic.

Table 18 (continued)

District	Name	Ref. Cap. (b/d)	-	Domestic Prod. (b/d)	=	Potential Imports
II	h. Ohio 1. Toledo**	430,000		23,000		516,000
	2. Rest	109,000		-		-
	i. Indiana 1. Chicago**	556,600		19,000		581,000
	2. Rest	43,500		-		-
	j. Illinois 1. Chicago**	445,000		106,000		904,000
	2. Wood River	562,000		-		-
						2,554,100
I	Buffalo	92,000		-		92,000

Choice of Crudes

Once markets have been defined, representative crudes for each producing area must be selected. Table 19 provides a complete list of the crudes used in this study. For all price comparisons in all markets, Redwater will always be used as the Canadian crude, except for exports through the Rangeland pipeline into district IV and the southwestern part of district II. Using Redwater for these markets was not acceptable in view of the pricing structure in Alberta.

In Alberta, as explained earlier (Chapter 3), all crudes are priced at the well so that the price of similar crudes is the same at Edmonton, The Rangeland system which does not go through Edmonton gathers crudes from Sundre and southward; that is why Rangeland API^{o}40 is only $2.85 at Sundre versus Redwater API^{o}35 at $2.92 at field gate.

All the prices in Table 19 are those in effect on July 1, 1972. In this Table, as for any other price calculations in this work, the Canadian dollar is taken at par with the U.S. dollar. On this same Table, two items have been added: the sulphur penalty and the discount off posted prices.

Sulphur Penalty

As mentioned earlier, sour crudes are less valuable to the refiner than sweet crudes. That is why a penalty is attached to crudes having more than

Table 19

List of Crudes

Name	API	Posted Price ($)	Discount %	Discount $	Sulphur % content	Penalty $
Redwater	35^{o}	2.92	-	-	0.54	.02
Oficina[a]	35^{o}	3.211	-	-	0.69	.04
Iran	34^{o}	2.467	21.7	.536	1.66	.24
Arabian	34^{o}	2.479	24.3	.602	2.46	.40
Libya	40^{o}	3.62	17.7	.640	.21	-
Algeria	44^{o}	3.539	23.0	.816	.16	-
Nigeria	34^{o}	3.409	15.0	.513	.13	-
Indonesia	35^{o}	2.96	15.0	.444	.07	-
East Texas	40^{o}	3.60	-	-	.25	-
APCO	36^{o}	3.52	-	-	.63[b]	.04
Wyoming	35^{o}	3.43	-	-	.74[b]	.06
Elk Basin	28^{o}	3.10	-	-	1.17[b]	.14
Alaska	35^{o}	3.20	-	-	NA	-
Rangeland	40^{o}	2.85	-	-	.29[c]	-
Long Beach	35^{o}	3.67	-	-	.44[b]	-

[a]No discount is known for Venezuela crude.

[b]Average taken from Oil and Gas Journal table for U.S. and Canadian crude.

[c]Canadian average.

Source: Petroleum Press Service; Platt's Oilgram Service.

a given amount of sulphur content. Usually, the sulphur content is given as a percentage of the weight of the crude. The penalty is two cents per barrel for every one tenth percent of sulphur content over 0.49 percent.[8] A comparison of the sulphur content of crudes is not readily available in the oil literature.[9] A partial list was published by the Oil and Gas Journal[10] and has been used to calculate penalties.

Discounts

Estimating comparative landed costs of offshore crudes on the basis of posted prices tends to distort the actual market relationship between crudes since posted prices are used for calculating royalty and tax payments and are not the prices paid by the buyers in transactions. Discounts off posted prices vary a great deal from one crude to another. A list of discounts for most crudes was available as of January 1, 1972 but not for July 1, 1972. Because there have only been price changes since January 1, but no tax structure changes, the same rate of discount prevailing January 1st has been applied to the July 1 prices. The estimates obtained should not be too far off since discounts are mainly affected by the total tax-paid cost of production.[11]

Tanker Rates

Other important data for the landed cost

calculations are the tanker freight rates. Accounts of the price variations of the tanker freight spot rates are regularly given in publications like the Platt's Oilgram Price Service and the Petroleum Press Service. Although these rates are effectively the rates that would have to be paid by any one refiner who would decide one day to get a tanker load of offshore oil, these rates are not necessarily those agreed upon between tanker owners and refiners in long-term contracts. In addition, most of the major oil companies have their own fleets, but no data showing the extent of the major oil companies' self-sufficiency in tankers is on hand.

The tanker rates used were taken from the Appendix E. of the U.S. Cabinet Task Force Report. These rates were based on the submissions of several oil companies and are probably closer to the long-term rates paid by the major oil companies. As a matter of comparison, the LR-1 rates in June, 1972 were at W75.4 on the spot market while the values used in the calculations will be equivalent to about W55.[12] The rates used for different routes are all shown on Table 20.

LANDED COSTS CALCULATIONS

It is now possible to establish the price comparisons. Ten items are considered in Table 21.

Table 20

Tanker Rates

From	To	$/Bbl.
Persian Gulf (ex Ras Tanuras and Kharg Island)	East Coast	.74
	Gulf Coast	.74
	West Coast South	.73
	West Coast North	.76
	Montreal*	.79
Alaska (ex Cook Inlet)	Vancouver	.19
	Puget Sound	.21
	San Francisco	.30
	Los Angeles	.35
Venezuela (ex Puerto la Cruz)	Gulf Coast	.23
	East Coast	.23
	Montreal	.32
Libya (ex Ras Lanuf)	East Coast	.296
	Montreal	.296
Algeria (ex Arzew)	East Coast	.261
	Montreal	.261
Nigeria (ex Forcados)	Gulf Coast	.354
	East Coast	.354
	Montreal	.385
Indonesia (ex Minas)	West Coast South	.498
	West Coast North	.506

*To Toronto, Montreal rates will be used, plus Seaway charges (.448/LT equals .059 ¢/Bbl), plus .04 ¢/Bbl in tanker rate. The .02¢/Bbl for pollution levy is included in Montreal rate.

Table 21

Estimated Costs of Crude Oils Delivered to Various Markets
(Dollars per Barrel)

A. Market - Vancouver

	Redwater[1]	Iran	Indonesia	Alaska
1	2.920	2.467	2.960	3.200
2	.05	-	-	.06
3	.441[2]	-	-	-
4[3]	-	.78	.526	.21
5	-	-	-	-
6	3.411	3.247	3.486	3.47
7	-	.536	.444	-
8	.02	.240	-	-
9	3.431	2.951	3.042	3.470
10		-.46	-.39	-.04

[1]Via Trans-Mountain pipeline.

[2]Including trunk pipeline allowance ($0.015) and feeder pipeline tariff ($0.026).

[3]Including pollution levy.

Note: For explanation of numerical titles at left of table, see text, page 82.

Table 21 (continued)

B. Market - Sarnia

	Redwater[1]	Oficina	Arabian	Libya
1	2.920	3.211	2.479	3.620
2	.050	-	-	-
3	.500	.100[2]	.100[2]	.100[2]
4	-	.439	.909	.415
5	-	-	-	-
6	3.470	3.750	3.488	4.135
7	-	-	.602	.640
8	.02	.04	.40	-
9	3.49	3.790	3.286	3.495
10		+.30	-.18	-.10

[1]Via interprovincial.

[2]Via interprovincial according to tariff schedule.

Table 21 (continued)

C. Market - Toronto

	Redwater[1]	Oficina	Arabian	Libya	Algeria	Nigeria
1	2.920	3.211	2.479	3.62	3.539	3.409
2	.050	-	-	-	-	-
3	.530	-	-	-	-	-
4[2]	-	.439	.909	.415	.380	.504
5	-	-	-	-	-	-
6	3.500	3.65	3.388	4.035	3.919	3.913
7	-	-	.602	.64	.816	.513
8	.02	.04	.40	-	-	-
9	3.520	3.69	3.186	3.395	3.103	3.400
10		+.17	-.31	-.22	-.60	-.10

[1]Via interprovincial.

[2]Including seaway charges at $0.448/LT of cargo and pollution levy ($0.02/Bbl).

Table 21 (continued)

D. Market - Montreal

	Redwater[1]	Oficina	Arabian	Libya	Algeria	Nigeria
1	2.92	3.211	2.479	3.620	3.539	3.409
2	0.05	-	-	-	-	-
3	.625	-	-	-	-	-
4[2,3]	-	.34	.81	.316	.281	.405
5	-	-	-	-	-	-
6	3.595	3.551	3.289	3.936	3.820	3.814
7	-	-	.602	.64	.816	.513
8	.02	.04	.40	-	-	-
9	3.615	3.591	3.087	3.296	3.004	3.301
10		-.02	-.51	-.42	-.79	-.29

[1]Via interprovincial at barrel per mile rate to Toronto.

[2]Via Portland is more expensive.

[3]In Feb. 1972, the Canadian Gvt. imposed a pollution levy of \$0.15/ton (\$0.02/Bbl) on tanker shipments.

Table 21 (continued)

E. Market - Puget Sound

	Redwater[1]	Iran	Indonesia	Alaska	Long Beach
1	2.920	2.467	2.960	3.200	3.67
2	.050	-	-	.06	.05
3	.441[2]	-	-	-	-
4	-	.73	.506	.21	.16
5	.105	.105	.105	-	-
6	3.516	3.302	3.571	3.470	3.88
7	-	.536	.444	-	-
8	.02	.240	-	-	-
9	3.536	3.006	3.127	3.470	3.88
10		-.51	-.41	-.07	+.34

[1]Via Trans-Mountain pipeline.

[2]Including trunk pipeline allowance ($0.015) and feeder pipeline tariff ($0.026).

Table 21 (continued)

F. Market - San Francisco

	Redwater[1]	Iran	Indonesia	Alaska	Long Beach
1	2.920	2.467	2.960	3.200	3.67
2	.050	-	-	.060	.05
3	.441[3]	-	-	-	-
4	.190[2]	.730	.498	.300	.16[4]
5	.105	.105	.105	-	-
6	3.706	3.302	3.563	3.560	3.88
7	-	.536	.444	-	-
8	.02	.240	-	-	-
9	3.726	3.006	3.119	3.560	3.88
10		-.70	-.51	-.17	+.15

[1] Via Trans-Mountain pipeline.

[2] Ex Burnaby (including $0.025/Bbl terminal charge).

[3] Includes feeder pipeline tariff ($0.026/Bbl) and trunk pipeline allowance ($0.015/Bbl).

[4] Ex Los Angeles.

Table 21 (continued)

G. Market - Los Angeles

	Redwater	Iran	Indonesia	Alaska	Long Beach
1	2.920	2.467	2.960	3.200	3.670
2	.050	-	-	.060	.050
3	.441	-	-	-	-
4	.240[1]	.73	.498	.350	-
5	.105	.105	.105	-	-
6	3.756	3.302	3.563	3.610	3.72
7	-	.536	.444	-	-
8	.02	.240	-	-	-
9	3.776	3.006	3.119	3.61	3.72
10		-.75	-.66	-.17	-.06

[1]Ex Burnaby (including $0.025/Bbl Terminal Charge).

Table 21 (continued)

H. Market - Billings

	Rangeland[1] 40°	Elk Basin (Wyoming)[3] 28°	Arabian	Iran
1	2.85	3.10	2.479	2.467
2	-	0.06	-	-
3	.470[2]	0.15	.510[4]	.51
4	-	-	.740	.74
5	.105	-	.105	.105
6	3.425	3.31	3.834	3.822
7	-	-	.602	.536
8	-	.14	.400	.24
9	3.425	3.44	3.63	3.52
10		+.25	+.22	+.11

[1]Posted at Sundre.

[2]Via Rangeland and Continental pipelines.

[3]Humble

[4]St. James to Kansas City at Interprovincial rates. Kansas City to Billings ($0.25/Bbl) via Platte and Marathon pipelines.

Table 21 (continued)

I. Markets - Wisconsin; Michigan, Bay City; Minnesota

	Wisconsin		Michigan, Bay City		Minnesota	
	Redwater[1]	Iran	Redwater[1]	Iran	Redwater[1]	Iran
1	2.92	2.467	2.92	2.467	2.92	2.467
2	.05	-	.05	-	.05	-
3	.382	.44[2]	.482	.42[3]	.485	.68[3]
4	-	.74	-	.74	-	.74
5	.105	.105	.105	.105	.105	.105
6	3.458	3.752	3.56	3.732	3.557	3.992
7	-	.536	-	.536	-	.536
8	.04	.24	.04	.24	.04	.24
9	3.498	3.456	3.60	3.432	3.597	3.696
10		-.02		-.15		+.12

[1] Via IPL Lakehead.

[2] From Chicago via Lakehead at IPL rates.

[3] From Detroit via Lakehead at IPL rates.

<u>Note</u>: Since the offshore crude is taken from points like Chicago and Detroit, the difference in cost of offshore and U.S.crudes will be the same as at these points.

Table 21 (continued)

J. Market - Kansas (El Dorado)

	Rangeland[1] 40°	Kansas[2] 36°	Arabian	Iran
1	2.85	3.52	2.479	2.467
2	-	.07	-	-
3	.72	.10	.26[3]	.26[3]
4	-	-	.74	.74
5	.105	-	.105	.105
6	3.675	3.69	3.584	3.572
7	-	-	.602	.536
8	-	.04	.400	.24
9	3.675	3.73	3.382	3.276
10		+.14	-.27	-.38

[1]Via Continental Marathon Platte pipeline. Sundre to Billings at $0.47/Bbl and Billings to El Dorado at $0.25/Bbl.

[2]APCO crude.

[3]St. James to Kansas (El Dorado) at IPL rates.

Table 21 (continued)

K. Market - Chicago

	Redwater[1]	Wyoming	E. Texas	Arabian	Iran
1	2.920	3.430	3.600	2.479	2.467
2	.050	.075	.085	-	-
3	.470	.370[3]	.280[4]	.240[5]	.240[5]
4	-	-	-	.740	.740
5	.105	-	-	.105	.105
6	3.545	3.875	3.965	3.564	3.552
7	-	-	-	.602	.536
8	.02	-	-	.400	.240
9	3.565	3.875	3.965	3.362	3.256
10		+.31	+.40	-.18	-.29

[1]Via interprovincial-lakehead.

[2]Via Humble Oil-Marathon-Chicago.

[3]Via Marathon-Platte-Marathon-Texaco/Cities Service.

[4]Via Shell-Cities Service-Gulf-Mobile-Texaco/Cities Service.

[5]Via Capline-Chicap (including $0.02/Bbl terminal charge).

Table 21 (continued)

L. Market - Detroit-Toledo

	Redwater[1]	Wyoming	E. Texas	Arabian	Iran
1	2.920	3.430	3.600	2.479	2.467
2	.050	.075	.085	-	-
3	.550	.480[2]	.205[3]	.300[4]	.300[4]
4	-	-	-	.740	.740
5	.105	-	-	.105	.105
6	3.625	3.985	3.890	3.624	3.612
7	-	-	-	.602	.536
8	.02	-	-	.400	.240
9	3.645	3.985	3.890	3.422	3.316
10		+.34	+.25	-.20	-.31

[1]Via interprovincial-lakehead.

[2]Via Marathon-Platte-Marathon-Buckeye.

[3]Via Gulf-Mid-Valley-Buckeye.

[4]Via Shell-Capline-Buckeye (including $0.02/Bbl terminal charge).

Table 21 (continued)

M. Market - Buffalo

	Redwater[1]	Wyoming	E. Texas	Arabian
1	2.920	3.430	3.600	2.479
2	.050	.075	.085	-
3	.550	.590[2]	.360[3]	.040[4]
4	-	-	-	.919[5]
5	.105	-	-	.105
6	3.630	4.100	4.050	3.543
7	-	-	-	.602
8	.020	.060	-	.400
9	3.650	4.160	4.050	3.201
10		+.51	+.30	-.43

[1]Via interprovincial-Lakehead.

[2]Via Marathon-Platte-Marathon-Buckeye-IPL/L.

[3]Via Gulf-Mid-Valley-Buckeye-IPL/L.

[4]Estimated tariff of an 80 mile pipeline from the shore to the refineries.

[5]Tanker charge to Toronto plus $0.01.

To save space on the table, the headings have not been repeated but numbered. The numbers denote:

1 - Posted Price
2 - Gathering Charges
3 - Trunk Pipeline Tariff
4 - Tanker Rate
5 - U.S. Import Tariff
6 - Total Apparent Landed Cost
7 - Discount Off Posted Price
8 - Sulphur Penalty
9 - Real Landed Cost
10 - Price Differential with respect to Redwater after gravity adjustment.

On Table 22, all relevant data for all markets have been tabulated. The first three columns show the delivered price of the Canadian crude, the cheapest off-shore crude, and the cheapest U.S. domestic crude in every market. Columns 4 and 5 then show the required posted price in Edmonton in order for Redwater to sell just at par with, first, the cheapest of all crudes available in the market, and, second, the cheapest available U.S. crude. It is then possible to find out for every posted price for Redwater which markets would be accessible to Canadian crude. These calculations are shown in Tables 23 and 24. The procedure followed in the case where a state has been divided in two distinct markets was to subtract the whole state production from the refining capacity of the first of the two markets in which Canadian crude enters.

INTERPRETATION OF RESULTS

In the case of free trade among imports, Table

Table 22

Comparison of Landed Costs of Crudes

Markets	1 Can.	2 U.S.	3 Off.	4	5
Puget Sound	3.54	3.47	3.02	2.85*	2.41
San Francisco	3.73	3.56	3.02	2.75*	2.22
Los Angeles	3.73	3.56	3.02	2.75*	2.17
Billings	3.43	3.68	3.54	3.17	3.04
Denver	3.71	3.71	3.64	2.92	2.85
Minnesota	3.60	4.32	3.72	3.64	3.04
Wisconsin	3.50	4.08	3.48	3.52	2.90
Kansas 1.**	3.68	3.81	3.29	3.06	2.54
2.	3.70	3.83	3.31	3.06	2.54
Michigan 1.	3.65	3.98	3.34	3.26	2.61
2.	3.60	4.10	3.45	3.42	2.77
Ohio 1.	3.65	3.98	3.34	3.26	2.61
2.	3.69	3.94	3.30	3.17	2.53
Indiana 1.	3.56	3.88	3.27	3.23	2.63
2.	3.63	3.75	3.27	3.04	2.56
Illinois 1.	3.56	3.88	3.27	3.23	2.63
2.	3.62	3.73	3.25	3.03	2.55
Buffalo	3.65	3.95	3.22	3.22	2.49
Vancouver	3.41	-	2.97	-	2.46
Prairies	2.94	-	2.92	-	2.90
Sarnia	3.49	-	3.31	-	2.74
Toronto	3.52	-	2.92	-	2.32
Montreal	3.62	-	2.82	-	2.13

*This is the required posted price when compared to Alaska crude, but only about 30,000 b/d of Alaska crude are exported. If a comparison is made with California crude, then the prices should read in order: 3.26, 3.07, 2.86.

**Categories 1. and 2. denote two separate markets, as in Table 18, p. 63.

Table 23

Free Trade Case

Posted Price	Market	Capacity (b/d)	Total
2.90	Billings	26,900	
	Wisc.	51,000	
	Minn.	134,500	
	Prairies	287,750	500,150
2.85	Denver	25,000	525,150
2.77	Mich. 2.*	32,000	557,150
2.74	Sarnia	220,800	777,950
2.63	Indiana 1.	537,600	
	Illinois 1.	339,000	1,654,550
2.61	Ohio 1.	407,000	
	Mich 1.	92,600	2,154,150
2.56	Indiana 2.	43,500	2,197,650
2.55	Illinois 2.	562,000	2,759,650
2.54	Kansas 1 & 2	244,000	3,003,650
2.53	Ohio 2.	109,000	3,112,650
2.49	Buffalo	92,000	3,204,650
2.46	Vancouver	127,300	3,331,950
2.41	Puget	306,000	3,637,950
2.32	Toronto	171,400	3,809,350

*For clarification of categories 1. and 2. see Footnote, Table 18, p. 63.

23 shows that a posted price of \$2.55 for Redwater would provide Canadian crude with all the markets it can satisfy. No posted price over \$2.90 was considered since for that price, Iranian crude could be shipped to Edmonton via Vancouver. If the Canadian market west of the N.O.P. Line is considered as captive, then a posted price of \$2.61 would exhaust all the Canadian export potential to the U.S.

In view of the option opened to U.S. refiners to swap their offshore tickets, the above treatment overestimates the competitiveness of Canadian crude. A U.S. refiner can swap his offshore tickets, usually with a coastal refiner, for domestic crude. The value of the ticket is not the difference between the delivered cost of U.S. crude minus offshore crude at the refinery but will usually sell for a value which is closer to the difference between the average price of U.S. crude on the Gulf Coast and the landed price of offshore in the same area. So in fact the real price of a barrel of offshore in any part of districts I-IV is the same and according to the data, is \$3.03 for all refiners, thus reducing considerably the competitive edge of Canadian crude.

Non-Conformity to Reality

The results from the free competition between imports model appear inconsistent with the present posted price of \$2.92 for Redwater; too much Canadian

crude is sold for the going prices. A plausible explanation is that the tanker rates used in the price comparisons are too low and that the impact of the tanker spot rates is higher than expected.

This argument is hardly convincing. To adjust tanker rates to present spot rates would increase costs by about 20 to 25 cents, which is not enough to explain what is really happening. As for the coastal refiner who will effectively buy crude with the tickets he gets from his allocation or from swapping arrangements, it is very likely that he must go into what could be called "permanent swapping arrangements" with inland refiners who will exchange their tickets permanently with this same refiner. The coastal refiner with a steady given amount of tickets available can then go into long term contracts with a tanker owner and thus avoid the higher spot rates.[13] The inland refiner who does not contract with tanker owners is also well aware of the long-term prices for tankers; long-term contracts are arrangements well documented in the oil literature; Platt's Oilgram has a very complete price information service.

<u>Special Status of Canadian Crude</u>

Another explanation might well be that Canadian crude is not competing against offshore crude on the same level. A somewhat special status for Canadian crude has often been implicitly recognized in the U.S.

oil import policies and statements by U.S. officials.

Special Status of Canadian Crude
As Expressed by U.S. Government

When the mandatory controls were enacted in 1959, Canadian crude was not submitted to a quota but was exempted under the overland exemption clause,[14] although there were intergovernmental agreements to limit quantitatively the flow of crude. At this time some form of hidden tariff was placed on Canadian crude since it was not considered as an eligible input for the allocation of import tickets for cheaper offshore crude.[15]

In district V, which enjoyed a special treatment at the beginning of the mandatory controls, the crude quota is set at the difference between estimated demand for the calendar year and estimated U.S. and Canadian supplies produced or shipped in the district, and so, in the words of the Cabinet Task Force, the producers of district V are totally protected from imports.[16] Later, in the report, the members express their views on the pricing of Canadian crude: "At present, Canadian oil actually sells for about 50 cents per barrel below the price of comparable U.S. oil in the Chicago market. This ANOMALY[17] apparently results from intra-Canadian price competition with imports in the Ottawa River Valley, and the fact that Canadian prices did not follow the 20 cent price increase in

U.S. oil last February."[18]

On March 21, 1972, Mr. Hollis M. Dole, Assistant Secretary of the Interior for Mineral Resources, said publicly that "the days of Canadian import restriction are numbered or, if they remain, they will be lifted toward the practical limit of Canadian crude capacity." According to the Journal, he meant before the end of this year or "certainly not later than the next year."[19] This special position enjoyed by Canadian crude could result from the fact that in the eyes of the U.S., Canadian oil is "nearly as secure politically and militarily as our own."[20]

Special Status of Canadian Crude As Shown by Industry Behavior

The situation announced by Mr. Dole seems to have arrived. From Table 17, replacing Alberta peak MER capacity by its present operational capacity of 1,254,000 b/d, the total Canadian production now runs at 1,573,000 b/d. Since 778,000 b/d are used in the Canadian market,[21] this leaves 795,000 b/d for exports to the U.S. The exports of crude to the U.S. were 756,000 b/d in 1971. Thus the line capacity was really fully used. The need for expanded facilities was emphasized lately in The Globe and Mail[22] when they mentioned that Alberta crude producers "will be hard pressed to substantially increase crude output above the present 1.15 million b/d because of restric-

tions on gathering pipeline capacity in the fields which has not kept pace with the capacity additions incorporated in the past year in the main transmission facilities."

In 1971, the capacity of the Trans Mountain Pipeline was increased to 380,000 b/d.[23] Such an expansion of this line raises two interesting points. First, this means that there is still a very good demand for Canadian crude in the Puget Sound area where offshore crude could be landed at 50 cents cheaper than Canadian, but is not; and second, the opening of the Prudhoe Bay production is probably not expected to capture that market in three or four years when production should go on stream. It rather suggests that Prudhoe Bay crude might replace offshore imported crudes in the San Francisco and Los Angeles markets, and at least partly bypass Puget Sound which is supplied by North American crude.

In 1970, there were important changes in the U.S. oil import regulations with respect to Canadian crude. In 1966, Canadian crude, although not submitted to a formal quota, was included in the total import quota of districts I-IV. In 1970, on December 22nd, a formal quota was placed upon Canadian crude as provided by the amendment of presidential proclamation 3279 of March 10, 1959. The provisions

now offered are those spelled out in revision 5 of the Oil Import Regulation I as amended through March 31, 1971.[24] A brief summary of section 23 of these regulations which deal with Canadian imports in districts I-IV follows.

A refiner who was using Canadian crude in the last half of 1970 is entitled to an historical allocation, any increase of which is set by the Oil Import Administration. The difference between the total Canadian quota and the amount allocated on an historical basis is then divided among other eligible refiners on an input basis. The eligibility condition is for the refiner to have a "facility capable of processing Canadian imports,"[25] although he could swap up to 50 percent of his allocation in exchange for U.S. crudes. A refiner receiving both a Canadian and offshore allocation can get an additional Canadian allocation, but only up to two thirds of the offshore allocation and it shall be charged against the latter.[26]

An important advantage now open to U.S. refiners using Canadian crude is the build up of an import position over time. In the allocation of Canadian crude, there are no specific limitations set upon the percentage of refinery input that can be imported. The past import history of a refiner is, in that respect, very important. Such a limitation

exists for offshore crudes which are allocated only an input basis to all refiners whether they are physically capable of processing it or not. Knowing the price differential between U.S. and Canadian crude, and the value of an offshore ticket, it is possible to express the percentage of Canadian crude rather than offshore that a refiner must have to make an equally profitable transaction. Let us give an example.

A refiner has a 100 b/d refinery which can be supplied with U.S. crude at $4.00 per barrel, Canadian crude at $3.50 per barrel, and offshore crude at $3.00 per barrel. Using only U.S. crude makes a total expenditure of $400.00 on inputs. If the refiner can have ten percent of his total input supplied with offshore crude, the total expenditure is $390.00. If the refiner wants to switch to Canadian crude, he will then need to supply at least 20 percent of his total crude requirements from Canadian sources to make an equally profitable deal. This can be expressed by the following relation:

$$a = \frac{c\ Pt}{Pus - Pc}$$

where a is the percent of Canadian crude input, c is the percent of offshore crude input, Pt is the price of an import ticket, Pus is the price of U.S. crude, and Pc is the price of Canadian crude.

Such a position build up seems to effectively

occur. In 1971, 756,000 b/d of Canadian crude were imported in the U.S., 545,000 b/d of which were for districts I-IV. Since the refining capacity of the refineries using Canadian crude is 2,463,150 b/d[27] in these districts, the average Canadian crude input of these refineries is about 22 percent. The total refining capacity of those refineries not using Canadian crude in these districts is around 8,400,000 b/d,[28] and they had to share 640,000 b/d[29] of offshore crude on 1971, thus making an average input of less than 7.5 percent.[30]

Reasons for such a build up, apart from the possible short run price advantage resulting from a large enough percentage of Canadian crude input, can also stem from the anticipation of higher prices for offshore crudes. The clauses of the 1970 Teheran agreement provide for an additional tax paid cost increase of some thirty two cents per barrel by 1975,[31] thus increasing the profitability of a switch to Canadian crude. Such a switch must be decided upon early by a refiner since allocations are given for a one year period and the position build up is a long run process.

In view of the constant overestimation of U.S. domestic crude production in the last couple of years, more versatility in the crude supply can be an asset to any refiner. A change in Canadian

nominations can be made every month whether it is in the amount allocated through a license or in a case of hardship where an additional allocation of Canadian crude can be obtained. Offshore supplies are not as flexible and it may take two or three months before a shipment from the Persian Gulf can be ordered and delivered.

As an addendum to this chapter, Table 24 has been included to illustrate what should be the posted price of Canadian crude should there be a North American continental energy policy where Canadian crude would officially have the same treatment as U.S. crude, or if Canadian crude was, in fact, already considered as an import that cannot be displaced by offshore crudes.

FOOTNOTES

[1] Oilweek, June 25, 1972, p. 23.

[2] Oil and Gas Journal, July 31, 1972, p. 85.

[3] Cabinet Task Force Report, op. cit., p. 38.

[4] Cabinet Task Force Report on Oil Import Control, "The Oil Import Question," p. 8.

[5] This fixed percentage has now, for any practical purpose, been abandoned in 1972; production in district I-IV runs at 8,342,000 b/d, while imports are at 1,435,000 b/d, which is 17 percent. The same treatment as in district V is now really being applied, (see Oil and Gas Journal, July 31, 1972, p. 87).

[6] Oil and Gas Journal, July 31, 1972, p. 85-87.

[7] Oil and Gas Journal, August 21, 1972, p. 32.

Table 24

Canadian vs. U.S.

Posted Price	Market	Capacity b/d	Total
3.64 & over	Canadian NOP	807,250	
	Minnesota	134,500	941,750
3.52	Wisc.	51,000	992,750
3.42	Mich. 2.*	32,000	1,024,750
3.26	Mich. 1.	92,600	
	Ohio 1.	407,000	
	Puget**	276,000	1,800,350
3.23	Illinois 1.	339,000	
	Indiana 1.	537,600	2,676,950
3.22	Buffalo	92,000	2,768,950
3.17	Billings	26,900	
	Ohio 2.	109,000	2,904,850
3.06	Kansas 1. & 2.	244,000	3,148,850
3.04	Indiana 2.	43,500	3,192,350
3.03	Illinois 2.	565,000	3,757,350
2.92	Denver	25,000	3,782,350

*For clarification of categories 1. and 2. see Footnote, Table 18, p. 63.

**About 30,000 b/d of crude is imported from Alaska.

[8]Information obtained from Imperial Oil Company.

[9]Oil and Gas Journal, January 31, 1972, p. 100.

[10]Oil and Gas Journal, November 11, 1968, p. 96.

[11]No discount applies to Canadian crude. The following check has been made to test that assertion. From the Summary of Monthly Statistics of the Alberta Oil and Gas Conservation Board, the posted prices shown for every field were multiplied by the total output of the field for the field for the year. All fields then summed up and the total obtained was then divided by the total number of barrels produced to give the average price of a barrel of crude. Then from the Crude Petroleum and Natural Gas Products Industry 1968, published by Statistics Canada (No: 26-213), the dollar value of total shipments of Alberta crude oil was divided by the total number of barrels to obtain the average price per barrel. If discounting has been practiced, a discrepancy between the weighted average field prices and the implicit average price would be expected. The two calculations resulted in virtually the same results ($2.5458 and $2.5447). The same test was made for the year 1958 when Canadian output had to be contracted after the Suez crisis and once again no evidence of discounting appeared.

[12]Tanker rates are given for different sizes of tankers; LR-1 is for tankers of 45,000 to 79,999 deadweight tons. The figures following the "W"s on the weighted average world tanker freights were assessed over the period from the 16th of one month to the 15th of the following month and are expressed in relation to Worldscale rate.

[13]Escalation clauses are sometimes included in long-term contracts; the spot rate can then affect the long-term rates.

[14]Mexico was also exempt for the same reason, although imports were limited by agreement to 30,000 b/d. See Shaffer, op. cit., Chapter 6 and Cabinet Task Force, op. cit., p. 8 ff.

[15]Import tickets are allocated as a percentage of a refiners aggregate input on a sliding rule basis, biased to favor the smaller refiners.

[16]Cabinet Task Force Report, op. cit., p. 10.

[17]Capital letters mine.

[18]Cabinet Task Force Report, op. cit., p. 45. There

have been price increases for Canadian oil since then, but it followed a similar 25 cent increase in the U.S. in 1970.

[19] Oil and Gas Journal, March 27, 1972, p. 39.

[20] Cabinet Task Force Report, op. cit., par. 427, B.

[21] Oilweek, June 5, 1972, p. 23.

[22] The Globe and Mail, Report on Business, August 23, 1972, p. 1.

[23] Trans Mountain Pipeline Company Annual Report, 1971.

[24] United States, Department of the Interior, Oil Import Administration.

[25] U.S. Oil Import Regulation I, Section 23-b.

[26] U.S. Oil Import Regulation I, Section 23-m.

[27] Oilweek, June 5, 1972, p. 26.

[28] U.S. Department of the Interior, Bureau of Mines, Mineral Industry Survey.

[29] Oil and Gas Journal, January 31, 1972, p. 86.

[30] This figure is favorably biased towards offshore crude since part of offshore imports are for petrochemical plants and some refineries also using Canadian crude.

[31] Oil and Gas Journal, March 20, 1972, p. 17.

Chapter 5

CONCLUSIONS

The first conclusion to draw from this exercise is that there is no free price competition between exports in the U.S. markets since the results obtained from such a model are in contradiction with reality. If the landed costs of imported crudes in the U.S. are not what directly determines their competitiveness, it does not mean that there is no form of price competition between imports.

The reason why free competition does not apply could stem from the U.S. oil import regulations which apply a different treatment to Canadian and offshore imports, thus altering the relative economic attractiveness of both crudes. The impact of the regulations on the long-range economic value of each crude, that stem from the historical import pattern of each refiner, the sliding rule basis for import tickets allocation and the restrictions on eligibility for allocations makes it very difficult to attach a number to the economic value of each crude and makes every case different. It appears that more detailed information on the position of each refiner should be obtained in future studies.

There is also quite an indication of the presence of non-price competition between imports: i.e., Canadian crude, as is the case for U.S. crude, cannot be displaced by offshore imports because it is part of the domestic supply. Remarks and declarations by U.S. officials bring some substance to that hypothesis. The claims regarding the precarious price position of Canadian crude by some private oil organizations like the Canadian Petroleum Association and company spokesmen are difficult to reconcile with the evidence in this study.

In summary, to state in clear-cut figures what the price of Canadian crude would have to be in order to be operating in the relatively elastic part of the demand function is not possible at this stage; more insight is needed on the goals and motivation of the U.S. government and the companies involved; but at least the following can be said.

In the middle 1960's, Canadian crude was considered as competitive in the U.S. Midwest markets and the rapid gains scored annually by Canadian crude are valuable proof of that. Since then the price of U.S. crudes has increased by 40 cents and Canadian crude by 25 cents plus an additional 20 cents to U.S. buyers because of the rise in price of the Canadian dollar. The mathematical formula outlined at the end of Chapter 4 has emphasized the direct

relation that exists between the price differential of Canadian and U.S. crudes and the price of import tickets. These tickets used to exchange for $1.45 in 1969.[1] Now they exchange for about 85 cents.

This 60 cent gap leaves ample room to believe that the position of Canadian crude has greatly improved and that a Canadian price increase of some 15-20 cents would only restore now the situation existing then. Finally, the stress imposed upon the crude transportation facilities in Canada by a too rapidly growing U.S. demand is an interesting sign that the present price of Canadian crude might be increased without any harm to its competitiveness.

FOOTNOTES

[1] Oil and Gas Journal, March 20, 1972, p. 15.

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